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August 11, 2017

VIA ELECTRONIC FILING

Mr. Joel H. Peck, Clerk
c/o Document Control Center
State Corporation Commission
Tyler Building – First Floor
1300 East Main Street
Richmond, Virginia 23219

RE: ***Application of Virginia Electric and Power Company in re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to § 56-597 et seq.***

Case No. PUR-2017-00051

Dear Mr. Peck:

Attached for filing in the above-referenced matter is the Direct Testimony and exhibits of Gregory Lander, which is being submitted on behalf of the Natural Resources Defense Council, Appalachian Voices, and the Chesapeake Climate Action Network (collectively, "Environmental Respondents"). This filing is being completed electronically, pursuant to the Commission's Electronic Document Filing system.

If you should have any questions regarding this filing, please contact me at (434) 977-4090.

Regards,

William C. Cleveland

William C. Cleveland

cc: Parties on Service List
Commission Staff

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

APPLICATION OF VIRGINIA ELECTRIC AND POWER COMPANY	)))	Case No. PUR-2017-00051
In Reference: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.	)))	

Summary of Direct Testimony of

Gregory M. Lander

On Behalf of

Environmental Respondents

August 11, 2017

Summary of Testimony of Gregory M. Lander

My name is Gregory M. Lander. I am head of Skipping Stone, Inc.'s Energy Logistics practice. My testimony focuses on the cost that Dominion Energy Virginia ratepayers will bear if the Atlantic Coast Pipeline is constructed. Contrary to a report by ICF International that the Company released in 2015, using data I obtained from the Company during this IRP process, I calculate that the Atlantic Coast Pipeline will increase costs for Dominion ratepayers between $1.61 and $2.36 billion.

In light of these unnecessary costs, I offer two proposals for how the Commission can shield Dominion ratepayers from these costs in the event that the pipeline is built.

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Direct Testimony of

Gregory M. Lander

On Behalf of

Environmental Respondents

August 11, 2017

Q. Please state your name and address.

A. My name is Gregory M. Lander. My mailing address is 83 Pine Street, Suite 101, West Peabody, MA 01960, and my email address is glander@skippingstone.com.

Q. What is the purpose of your testimony today?

A. My testimony addresses two primary concerns. First, in discussing the proposed Atlantic Coast Pipeline (the "ACP"), the Company has publicly released a report from ICF International claiming that the ACP will save Company ratepayers money.[1] According to the ICF report, the ACP will provide access to natural gas located at the Dominion South Point pooling location, which will allegedly be lower cost than natural gas from either Henry Hub or Transco Zone 5. ICF further asserts that the price savings are so great that they more than offset the increased transportation costs associated with using the new ACP, thus producing a net customer savings.

Q. In your analysis, does Dominion's 2017 Integrated Resource Plan ("IRP") support this conclusion?

A. No, it does not. In my analysis, detailed below, using Dominion's own modeling numbers and assumptions from this year's IRP, the costs of transportation along the Atlantic Coast Pipeline will actually outweigh the reduced natural gas prices at Dominion South Point. As such, using Dominion's own 2017 IRP data, the ACP will actually ***<u>increase</u>*** customer costs between $1.61 and $2.36 billion.

Q. What else does your testimony include?

[1] *The Economic Impacts of the Atlantic Coast Pipeline*, prepared for Dominion Transmission, Inc. by ICF International (Feb. 9, 2015) (the "ICF Report"), *available at* https://www.dominionenergy.com/library/domcom/pdfs/gas-transmission/atlantic-coast-pipeline/acp-icf-study.pdf, at 5 ("Between 2019 and 2038, ICF estimates a net annual average energy cost savings of over $377 million dollars - $243 million in Virginia, and $134 million in North Carolina. These benefits accrue to both natural gas and electric consumers and add to the construction and local tax benefits identified in other studies.").

A. If the Company does build the ACP, I offer two solutions the Virginia SCC could employ to shield Dominion ratepayers from these increased costs.

Qualifications

Q. What is your educational and professional background?

A. I graduated from Hampshire College in Amherst, MA, in 1977, with a Bachelor of Arts degree. In 1981, I began my career in the energy business at Citizens Energy Corporation in Boston, MA ("Citizens Energy"). I became involved in the natural gas business of Citizens Energy in 1983. Between 1983 and 1989, I served as Manager, Vice President, President and Chairman of Citizens Gas Supply Corporation (a subsidiary of Citizens Energy). I started and ran an energy consulting firm, Landmark Associates, from 1989 to 1993, during which time I consulted on numerous pipeline open access matters, a number of Order No. 636 rate cases, pipeline certificate cases, fuel supply and gas transportation issues for independent power generation projects, international arbitration cases involving renegotiation of pipeline gas supply contracts, and natural gas market information requirements cases (Order Nos. 587 *et seq*.). In 1993, I founded TransCapacity LP, a software and natural gas information services company. Since 1994, I have also been a Services Segment board member of the Gas Industry Standards Board ("GISB") and its successor organization, the North American Energy Standards Board ("NAESB"). During the period 1994 to 2002, I served as a Chairman of the Business Practices Subcommittee, the Interpretations Committee, the Triage Committee, and several GISB/NAESB Task Forces. I am currently a Board Member of NAESB and have served continuously in that capacity since 1997. Skipping Stone, Inc. ("Skipping Stone") acquired TransCapacity in 1999, and since that time I have headed up Skipping Stone's

Energy Logistics practice, where my specialization has been interstate pipeline capacity issues, information, research, pricing, acquisition due diligence and planning. In 2001, Skipping Stone launched CapacityCenter.com, a pipeline capacity information service. In 2004, Skipping Stone was acquired by Commerce Energy Group, a national retail energy services provider. In 2005, I was appointed President of Skipping Stone, which operated as a wholly owned subsidiary of Commerce Energy Group. In 2008, I purchased substantially all of the assets of Skipping Stone and now operate essentially the same business as before the Commerce Energy transaction as Skipping Stone, LLC.

From 1984 to present, I have maintained a deep familiarity with the wide range of pipeline transportation issues; beginning with access to pipeline capacity to make competitive sales, resolution of the pipeline take-or-pay contracting regime, pipeline affiliate marketer concerns; restructuring of the pipelines from merchants to transporters and thereafter, with respect to pipeline capacity issues beginning with the definitions of what constituted a pipeline capacity "right" for the purposes of formulating the newly commenced capacity release and capacity rights trading business process. I continue to be involved in nearly all facets of the capacity information and trading business as part of my duties at Skipping Stone. In addition, I have been the lead principal on all 50+ pipeline and storage mergers and acquisitions ("M&A") transactions as well as all pipeline and storage facility expansion projects for which Skipping Stone has been retained by potential purchasers and project sponsors to provide economic due diligence consulting and market analysis.

Q. Have you filed testimony in regulatory proceedings previously?

A. I filed testimony in FERC proceedings including Docket No. RP01-486-000, addressing, among other things, the reasons why there was a shortfall of firm capacity on the El Paso Natural Gas ("EPNG") system in the years 2000-01. I filed testimony in Docket No. RP04-251-000, which was an EPNG proceeding regarding pathing and segmentation. In Docket No. RP08-426-000, (also an EPNG proceeding) I sponsored answering and supplemental answering testimony. I also filed testimony Docket No. RP10-1398 ("EPNG") when it went to the hearing in 2014 as the first fully litigated EPNG Rate case in more than three decades. I also filed testimony in Massachusetts DPU cases 13-157, 15-34, 15-48, 15-39 and Maine PSC case 2014-00071. All of the state regulatory cases involved state regulatory determinations with respect to Local Distribution Companies or electric LSEs entering into pipeline agreements for new capacity.

Q. Are you submitting attachments along with your testimony?

A. Yes. They are:

1. Exhibit Lander-1
2. Exhibit Lander-2
3. Exhibit Lander-3
4. ER 1-1
5. Attachment ER Set 1-1 (a)
6. ER 1-40
7. Attachments ER Set 1-40 (AV) (1)
8. ER 3-07
9. Attachment ER 3-07 (DEH)
10. ER 3-9
11. ER 4-10
12. ER 4-12
13. ER 4-13
14. ER 6-18

Q. What issues will your testimony cover?

A. I will cover what I believe is a contradiction between public statements adopted by the Company with respect to the "value" of the Atlantic Coast Pipeline ("ACP") and the Company's own projections used in the IRP as to the likely "value"—or rather net cost to ratepayers—of the ACP. In addition, I propose two mitigation measures that the Virginia SCC can adopt to shield ratepayers from what I calculate, using the Company's own projections, to be the net cost to ratepayers as a result of the Company's subscription to transportation service on the ACP.[2] I perform these calculations based upon a series of assumptions as to rates to be paid by VPSE to the ACP and assumptions used by the Company as to gas prices.

Q. When you refer to the Company's public statements about the ACP's value, are you referring to this year's IRP?

A. No. I am specifically referring to the February 9, 2015 ICF report prepared for Dominion Transmission Inc. ("DTI") that the Company made public at that time.

Q. What did ICF conclude about the ACP in 2015?

A. ICF concluded that the ACP would produce a net savings for Dominion customers.

Q. On what did ICF base their calculations of potential savings?

A. ICF presented savings as a result of lower gas prices into ACP as represented by prices at the supply pooling point known as Dominion South Point plus the cost of transportation on ACP versus regional gas prices in Transco Zone 5. Dominion South Point is the

[2] The Company states in its IRP that, "In August 2014, the Company executed a precedent agreement to secure firm transportation services on the ACP." 2017 IRP at 72. Technically, this is incorrect. Pursuant to an SCC-approved affiliates agreement, a Company subsidiary, Virginia Power Services Energy, Corp. ("VPSE") is the signatory on the precedent agreements. The Company, and thus its ratepayers, however, ultimately bear the cost of all precedent agreements that VPSE signs. *See Petition of Virginia Electric and Power Company - To revise its fuel factor pursuant to Va. Code § 56-249.6*, Case No. PUR-2017-00058, June 14, 2017 Hearing Tr.at 45:6-10.

pricing point in Appalachia that is accessible to DTI and the proposed ACP line. Transco Zone 5 is the segment of Transcontinental Gas Pipeline ("Transco") that runs from a point in North-Central South Carolina to the Virginia/Maryland border.[3] Historically, as presented in the ICF Report, prices of gas at Dominion South Point have been higher than prices a Transco Zone 5. This is about to change.

Q. Does the Company's 2017 IRP reflect changes in the relationship between gas prices at Dominion South Point and gas prices at Transco Zone 5?

A. Yes, these changes are captured in the Company's response to ER 4-10 and ER 4-12, which presents future projected pricing data (basis) provided to the Company for use in its IRP Modeling. I will get to this below.

Q. Before you get to discussing how the pricing relationships between Dominion South Point and Transco Zone 5 will change, please explain how prices for Dominion South Point and Transco Zone 5 are calculated for the purposes of your testimony.

A: Sure. Prices of Dominion South Point determine prices for gas into the DTI pipeline, which delivers gas to the Local Distribution Companies ("LDCs") that serve 4 of the 18 plants identified by the Company in Attachment ER 3-07 (DEH). To estimate the cost of gas used to generate electricity at plants served directly (or indirectly) by DTI, one needs to calculate the "delivered" cost of gas, which is the sum of the price of gas at Dominion South Point, plus variable transportation costs through DTI, plus variable transportation costs through the LDCs (both costs inclusive of fuel used to move the gas plus an additional cost associated with lost and unaccounted for gas).

[3] There are six distinct Transco Zones and most have at least one liquid natural gas pricing location associated with the Zone.

Q: What is the cost of fuel?

A: The "cost of fuel" or fuel rate on DTI is roughly 2%; which means that DTI delivers approximately 98% of the gas they receive. If gas costs $2.00 per Dth, this fuel rate would add approximately another $0.04 per Dth to the delivered price/cost of gas.

Q: Is the "delivered" price of gas the same as the All-in Cost of gas?

A: No. To calculate an All-In Cost of Gas, one would also take into account the amounts paid to reserve capacity on the pipeline (and the LDC if such reservation costs are paid) and divide those costs by the units transported to arrive at a per unit transportation reservation cost, which would be added to the variable costs (gas and capacity usage costs). Typically the 100% load factor equivalent of the DTI Firm Transportation charge is about $0.14 per Dth.

Q: Why is the load factor important?

A: 100% load factor equivalent assumes the contract holder uses all of their capacity every day. In contrast, if a contract holder uses only 80% of their reserved capacity (meaning they are an 80% load factor customer), the effective cost for the units of DTI capacity used becomes $0.175 per unit used (*i.e.,* $0.14 divided by 0.8 = $0.175).

Q: How do these calculations about the cost of gas from Dominion South Point compare to the calculations about the cost of gas in Transco Zone 5?

A. In contrast to the above rough calculations of Dominion South Point (into the pipe prices) moved forward to market (*i.e.,* where the gas is burned), the prices in Transco Zone 5 are prices that are already reflective of prices "out of the pipe" (*i.e.,* prices at the market location as opposed to prices at the supply location). The reported prices for Transco Zone 5 determine prices for gas delivered within Transco's Zone 5 (again, the segment of

Transco pipeline that runs from a point in North-Central South Carolina to the Virginia/Maryland border). Transco is the pipeline which delivers gas to the one (1) plant served directly by Transco and the five (5) plants served by LDCs (6 plants in total of the 18 plants) as identified by the Company in Attachment ER 3-07 (DEH).

Seven (7) plants are served either directly by (or by LDCs served by) Columbia Gas Transmission ("TCO") and one (1) plant is served by Cove Point LNG's pipeline. The 14 of 18 plants not served by LDCs served by DTI are all plants whose gas supplies are driven by Transco Zone 5 pricing (*See* ER 1-1(a) and ER 4-13) – that is, gas prices at the market locations where gas is delivered for gas-fired generators of the Company.

Power Station[4]	**Pipeline / LDC**
Bellemeade	City of Richmond
TCO - Chesterfield	Columbia Gas of Virginia
Gravel Neck	Columbia Gas of Virginia
Gordonsville	Columbia Gas of Virginia
Eliz River	Columbia Gas of Virginia
Remington	Columbia Gas of Virginia
Altavista	Columbia Gas of Virginia
Hopewell	Columbia Gas of Virginia
Bear Garden	Columbia Gas of Virginia
Bremo	Columbia Gas of Virginia
Warren County	Columbia Gas Transmission
Possum Point	Cove Point Pipeline
Rosemary	Piedmont Natural Gas
Brunswick County	Transcontinental Gas Pipeline Company, LLC
Darbytown	Virginia Natural Gas
DTI-Chesterfield	Virginia Natural Gas
Yorktown	Virginia Natural Gas
Ladysmith	Virginia Natural Gas

[4] *See* Attachment ER 3-07 (DEH).

Q. Do you take issue with the statement by the Company in ER 1-1(a) or ER 4-13 that the Delivered Price at Transco Zone 5 was assumed to apply to all gas fired generating units within the DOM Zone?

A. No. It is a very reasonable assumption as to the 14 of 18 plants, given the dynamics of the gas market and the locations of the Company plants.

Q. Do purchases of gas for the plants where Transco Zone 5 pricing is assumed also have transportation costs associated with them?

A. For many of the purchases yes, for others no. When gas is bought from sellers on a "delivered to the plant" (or LDC) basis, the price of the gas includes the costs to the seller of the transportation. When capacity held by VPSE is used, then yes, transportation costs, including reservation charges are additive.

Q. Would it be fair to say that including those costs of transportation for the plants served by Transco in Zone 5 would yield prices roughly the same as those prices charged by sellers making delivery point sales in Zone 5?

A. Transco's rate design is much more complicated than DTI's and getting precise figures for receipt point purchase prices and then adding transportation costs (including load factor equivalents for reservation charges) would probably yield All-In Cost of Gas prices close enough to Zone 5 prices that relying on Transco Zone 5 prices is a very good proxy for the All-In Cost of Gas for the purposes of this testimony.

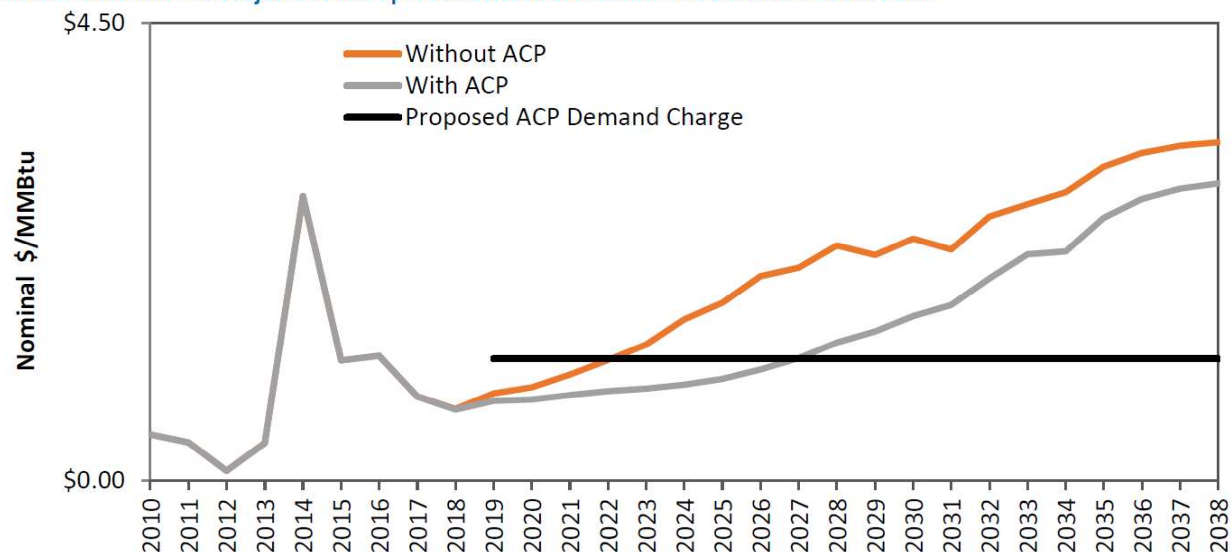
Q. Can you now relate this discussion on All-in Cost of Gas to the ICF report as to the value of ACP?

A. Yes. In the ICF Report, ICF estimates two pertinent "values" to the ACP line. First, it states that the ACP will provide access to lower-cost gas at Dominion South Point and that the cost savings in gas more than offset the increased transportation costs associated with using the new ACP. The ICF Report states:

> As seen in Exhibit 8, ICF estimates that, as compared to purchasing gas supplies delivered into the market, ACP gas buyers could save \$1.61/MMBtu on average by transporting Appalachian Basin gas on ACP – far exceeding the proposed transportation rate on the pipeline. The cost savings enabled by the ACP occur early in the life of the project and grow steadily over time.[5]

Second, it presents two views of Transco Zone 5 prices; one with ACP and one without ACP. See ICF Exhibit 8 below:

Exhibit 8: Historical and Projected Price Spread between Transco Z5 and Dominion South Point



Source: ICF

This presentation provides the ICF view of an historic and future "price spread" between Dominion South Point and Transco Zone 5.

[5] ICF Report at 9.

Q. What is a "price spread"?

A. A price spread is a metric used to determine the relative difference between prices at two different liquid gas pricing locations (*i.e.*, which pricing location is the lower or higher priced depending on viewpoint).

Q. How do you calculate a price spread?

A. All price spreads begin with a comparison of gas prices in a specific location against gas prices at the Henry Hub, *i.e.* the "basis" for that location. In this instance, I would, and ICF did, first calculate the price differential (basis) between Henry Hub and Dominion South Point. Then one would calculate the price differential (again basis) between Henry Hub and Transco Zone 5. Price spreads are then calculated by taking the difference between the "basis" of one location ("Dominion South Point") and comparing it to (*i.e.*, subtracting it from) the "basis" of the other location. If the difference (basis) between Henry Hub and Dominion South Point (Location 1) is negative $1.61, and the price differential between Henry Hub and Transco Zone 5 (Location 2) is positive $1.00 the price spread is $2.61 between Dominion South Point and Transco Zone 5 (*i.e.*, $1.00 minus ($1.61) = $2.61).

Q. What does a price spread of $2.61 between Dominion South Point and Transco Zone 5 mean?

A. This implies that as long as the All-In Cost to transport gas from Dominion South Point to Location 2 is less than the Price Spread, that there would be savings. Said another way, transportation costs (all of them) from Dominion South Point to Location 2 would have to be less than the Price Spread between Dominion South Point and Location 2 (*i.e.*, Transco Zone 5) for there to be a savings associated with buying Dominion South Point gas and transporting it to Location 2 on the ACP instead of just buying the gas at Location 2 – where the gas-fired generators are located.

Q. You said that the pricing relationships between Dominion South Point and Transco Zone 5 will change, please discuss this.

A. Not only is it my view that the pricing relationship between Dominion South Point and Transco Zone 5 will change from the historic relationship, it is also the view of the Company in this IRP.

Q. Please explain further.

A. In response to ER 4-10, the Company provided 200 iterations of future basis for each month from January 2017 through December 2042.[6] In response to ER 4-12, the Company identified Iteration 123 as the "Medium Expected Levelized Average Cost" for the No CPP Plan (Plan A). I loaded the entire data series (all 200 iterations) from Attachment ER 4-10 (AV) into a database and then did two extractions from that database. One extraction was all months for all years of Iteration 123. The other extraction was an average of all 200 Iterations for all months of all years. In each extraction, I extracted Dominion South Point and the Transco Zone 5 Basis figures.

Q. Why did you pick both Iteration 123 and the average of all 200 Iterations?

A. I picked Iteration 123 because that was the medium price expectation picked by the Company under Plan A No CPP. I then picked an average of all 200 Iterations because from a modeling and analysis point of view picking the average of all Iterations provides another view as to the totality of potential expected outcomes, and it should provide a

[6] Attachment ER Set 4-10 (AV). Due to the size of the spreadsheet, it is not attached as an exhibit to this testimony but is available upon request.

band of reasonableness with which to evaluate the picking of a single Iteration as representative of Medium Expectations.

Q. What did you find after doing these two extractions?

A. I found that over the 20 years of the initial term of VPSE's contract with ACP that the average basis for Dominion South Point, as used in the Company's 2017 IRP Model (*i.e.,* Iteration 123), was ($0.74) (*i.e.,* $0.74 less than Henry Hub). Likewise, over the same period, I found that the Transco Zone 5 basis, as used in the Company's 2017 IRP Model (again Iteration 123), was ($0.28) (*i.e.,* $0.28 less than Henry Hub). This yields a "Price Spread" of only $0.46 (forty six cents) (*i.e.*, ($0.28) minus ($0.74) = $0.46).

Q. How does this compare to ICF's 2015 estimates of the Dominion South Point / Transco Zone 5 price spread?

A. This is a far cry from not only the ICF figures for Dominion South Point as being ($1.61) to the Hub (*i.e.,* supposedly "paying" for the cost of ACP) but also far from the "price spread" in ICF's Exhibit 8, which appears to show that the price spread with ACP begins at a value that is slightly less that what I estimated from the Exhibit was about $1.40 (which appears to be the "Proposed ACP Demand (*i.e.,* reservation) Charge") rising to an approximately $3.00 Price spread by 2038.

Q. What did you do next?

A. Next, I took these two extractions and made a model (Exhibit Lander-3) which calculated the Price Spread (*i.e.,* Value of ACP) averaging the monthly basis for each of Dominion South Point and Transco Zone 5 by year and deriving the Price Spread (ACP Value) by year for each of the 20 years of the VPSE-ACP contract.

Q. What did you do after that?

A. I then took my estimates of the 100% load factor cost to VPSE of the ACP contract and subtracted them from the Value by year of the Price Spread to identify Net Cost of ACP to ratepayers.

Q. What estimates of ACP 100% load factor costs did you use?

A. I used two different 100% Load Factor costs. One was based upon the 100% Load Factor rate published by ACP in its Exhibit P to the FERC application filed by ACP. The other was a discount to that rate which I have found to be a typical discount accorded subscribing Foundation Shippers (of which VPSE is one).

Q. What is that typical discount, and what 100% Load Factor rate would result?

A. In my experience a very typical discount to Foundation Shippers is 20% off of the Exhibit P rate. In this case, with an approximately $1.75 per Dth 100% load factor rate, I would estimate that the Foundation Shipper rate would be $1.40 per Dth at 100% Load Factor.

Q. Is it customary to use the 100% load factor equivalent of the combined reservation and usage rates to make an All-in Cost of Gas estimation?

A. It depends on the expected load factor that the shipper will make use of the totality of capacity in their portfolio, and what kind of shipper they are.

Q. Please explain.

A. Well, a producer, which has a substantially level flow from their wells every day, can expect to see their cost of transportation, which determines the All-In Cost of Gas at their sales point(s) to be very close to 100% usage of capacity and thus the 100% load factor rate is reasonable. On the other hand, if the shipper is a shipper with seasonal or weather-sensitive load, like a generator with a portfolio of assets to serve weather-sensitive customers or an LDC, their actual realized load factor may be very much lower, making the effective All-In Cost of Gas (with the lower load factor) much higher. For instance, for a company with a reservation rate of $1.39 that operates at 80% load factor, the effective transportation rate per unit actually used becomes $1.7375; an increase of $0.3475 per Dth per day.

Q. So, are you possibly understating the "cost" of ACP by using the 100% load factor equivalent?

A. I am being somewhat generous as to the probable actual cost–in-use of the ACP line. Nevertheless, I used the 100% load factor equivalent, because it appears that is what ICF used in its report. Were I to assume an 80% load factor usage by the Company of its capacity portfolio, then the net cost of the ACP portion of its portfolio would be commensurately higher and the net cost to ratepayers, in turn, would be higher as well.

Q. Getting back to the Price Spread / Net Cost of ACP to the Company Ratepayers model, did you make any other assumptions?

A. Yes. I also assumed that every five years ACP would have a rate case which would lower return to account for depreciation. In this case I estimated that rates would decline about 10% every five years. I did this because of two likely reasons. One, a pipeline may be responding to its customers' desires to re-calibrate rates to take account of cost changes (especially return as a function of depreciation and Accumulated Deferred Income Taxes which also reduces rate base) and would do so by filing a rate case under Section 4 of the Natural Gas Act. Two, FERC has what are known as Natural Gas Act Section 5 rights to call a pipeline in for a rate case to reduce its rates, to the extent FERC can prove the pipeline is over-earning. While there is not a lot of experience as yet with the newest greenfields pipelines, as to periodic rate declines, historically, this had been the case, so it's not an unreasonable assumption to make here. That said, if the periodic, every five years or so, rate case and commensurate reductions do not occur for the ACP, then the net cost to ratepayers over time would be significantly higher than I have assumed in my modeling as to the net cost of ACP to ratepayers.

Q. Does this assumption make ACP more "valuable" as rates go down?

A. To some extent yes. However, my calculations, even with ACP rates declining, show there is never a net benefit to the Company ratepayers. In fact based upon the Company basis projections used in the Company's 2017 IRP, there is a net cost to the Company ratepayers throughout the term of the VPSE-ACP contract. This net cost arises from the precipitous decline in basis (under both the Iteration 123 and under the average of all 200 iterations) for both Dominion South Point and Transco Zone 5, which together drop the "Price Spread" or "Value" of ACP precipitously compared to what ICF posited. In addition, if the VPSE contract (which was not made available by the Company, even though it was requested) is a negotiated, fixed price, contract for the duration of the initial term, the Company customers would not see the benefit of lower rates coming out of any rate case.

Q. Based upon these calculations what did your model present as the net cost under the four cases you ran, that is, Case 1: Iteration 123 with ACP initial rates of $1.75 declining with periodic rate cases, Case 2: Iteration 123 with ACP initial rates of $1.40 also declining with periodic rate cases; Case 3: Average of All 200 Iterations with ACP initial rates of $1.75 (also declining) and Case 4: Average of all 200 Iterations with ACP initial rates of $1.40 (also declining)?

A. The net costs over 20 years are set forth below:

Case	**Net Cost to the Company Ratepayers**
Case 1: Iteration 123 with ACP initial rates of $1.75, declining with periodic rate cases	$2,287,635,333 or ~$2.29 Billion
Case 2: Iteration 123 with ACP initial rates of $1.40, also declining with periodic rate cases	$1,626,686,958 or ~ $1.63 Billion
Case 3: Average of All 200 Iterations with ACP initial rates of $1.75 (also declining)	$2,319,970,794 or ~ 2.31 Billion
Case 4: Average of all 200 Iterations with ACP initial rates of $1.40 (also declining)	$1,660,972,419 or ~ $1.66 Billion

(*See* Exhibit Lander-3 for derivations)

Q. So, using the Company's 2017 IRP data, does it appear to you that the Company ratepayers do not see net savings flowing from the VPSE contract with ACP?

A. Yes, but not only that, it may be even worse than presented above because even if all the gas is used in the most efficient Combined Cycle Turbines with heat rates approaching 6,500 Btu/Kw or 6.5 Dth/MWH, the actual cost for electricity is higher because only 65% or so of the energy in gas is converted to electricity under the most favorable of conditions. Under this set of parameters, the costs translated into electric costs would be between \$2.5 Billion and \$3.5 Billion. While this efficiency factor would apply to gas plants attached to any pipeline, the Company has embarked on replacing its coal-fired units with gas fired units, which according to the ICF Report (which also posits nuclear unit retirement) leads to an increase in gas demand in the future.

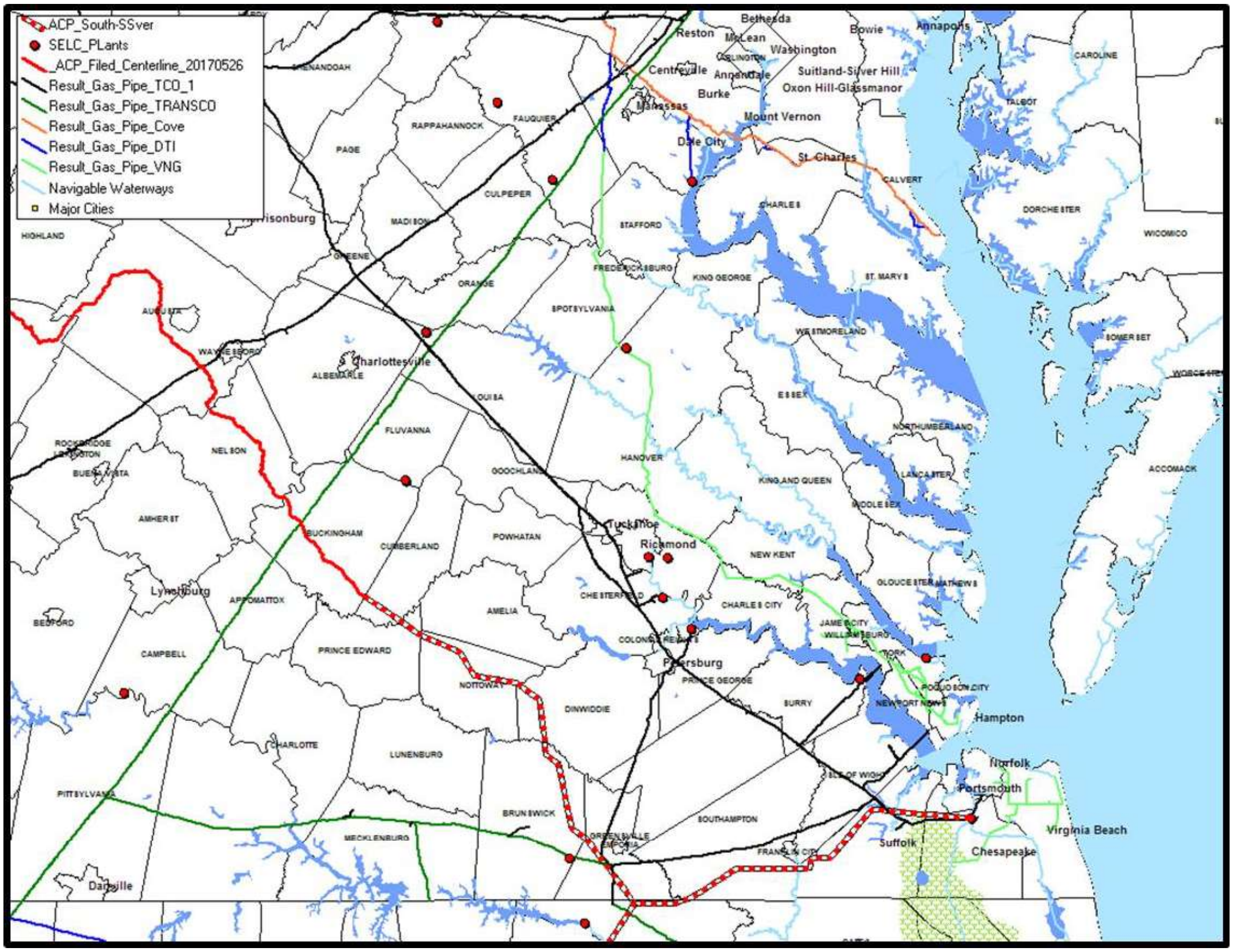
Q. Wouldn't the ACP have other benefits to the Company ratepayers?

A. First of all, the ACP will not directly connect to any current natural gas power plant, nor will it directly connect to any future natural gas power plant identified in the 2017 IRP. This includes the Greensville Plant. According to the Company's Response to ER 3-9, "[t]he Company's Greensville County Power Station will receive firm capacity from the Transcontinental Gas Pipe Line, and will have access to the Atlantic Coast Pipeline." Notably, having "access" is not the same as being "directly connected".

Q. What does this mean?

A. This means that all the Company plants will still have to get their gas from the last pipeline in the chain. The ACP may deliver to Transco in Zone 5, but that only means that the Company will still rely on Transco to get their gas to their generating stations. Skipping Stone has provided a map Exhibit Lander-1, upon which it has located both the Company power plants listed in the Company Response ER 3-7 as well as the pipelines in the same geographic regions. In addition, in Exhibit Lander–2, Skipping Stone has provided a column in addition to those provided by the Company in Response ER 3-7 that provide the approximate "as the crow flies" mileage from the nearest extent of the ACP line to each such plant. Fifteen of the plants are situated more than 20 miles (more than approximately \$70-\$80 Million dollars' worth of pipeline cost away) from the ACP.

The three plants that are within 20 miles from ACP lie between one and approximately six miles from the nearest ACP route, again "as the crow flies".



Please note that the rendering of the ACP line was done by Skipping Stone from an available ACP GIS layer to the border between Buckingham and Cumberland Counties Virginia and from an available ACP map of the balance of the Virginia extent of ACP as Skipping Stone did not have access to the actual GIS layer for the entire ACP route.

Q. Does the fact that much of the gas on ACP would be delivered to Transco in Zone 5 account for the Transco Zone 5 basis being so much closer to the Henry Hub in the future than it is today, and was during the historic period used by ICF in their Report?

A. Yes. The ACP will greatly increase supply available in Transco Zone 5 and, as a result, will have a large depressing effect on Transco Zone 5 basis (which drives prices). Moreover, even without the ACP, at least three other current projects will lower prices in Transco Zone 5: (1) Atlantic Sunrise, (2) the general reversal of Transco from Leidy to the Southeast, and (3) the potential Mountain Valley Pipeline. Each of these three will result in a vast increase in Appalachian-sourced supply being available in and to Transco Zone 5. Furthermore, it appears this likely effect is captured in the Company's Risk assessment in the 2017 IRP.

Q. Would there be a mechanism that you could describe that would shield the Company ratepayers from the projected effect of this net cost of ACP on gas used to generate electricity?

A. There are two that might achieve such mitigation.

Q. Please describe the first.

A. First, a little background is needed. Under the arrangement between VPSE, Virginia Power Energy Marketing ("VPEM") and the Company, titled the Affiliate Fuel Service Agreement and what I will term the Fuel Management Agreement, VPSE contracts for capacity and gas (including from VPEM). VPEM is a wholesale electricity and wholesale gas merchant. This means they make sales to others aside from VPSE. In addition, VPEM is the agent appointed to administer much of the pipeline capacity held by VPSE.

In fact, as of January 2016[7], VPSE held (and still holds) 1,026,919 Dth/d (1.026 Bcfd) of transportation capacity on interstate pipelines. In addition, VPSE also held (and still holds) 3 Bcf of storage capacity[8]. Of the transport capacity, all but 105,000 Dthd (~10%) can directly serve or has in path capacity rights able to serve the Company power plants. With respect to the approximately 1 Bcfd of transport capacity and the 3 Bcf of storage capacity, VPEM is VPSE's agent for all 3 Bcf of the storage capacity and 0.604 Bcfd of the VPSE transport capacity[9]. This means that under the Fuel Management Agreement, VPEM controls nearly 60% (58.8%) of this 1 Bcfd of transport capacity by means of its Agency status. In addition to the greater than 0.6 Bcfd of VPSE capacity VPEM controls; VPEM has another 0.22 Bcfd of capacity in its own name which it enables it to serve plants in the Northeast and to also fill the VPSE storage it controls[10].

Q. Go on.

A. Even though VPEM explicitly controls all VPSE capacity, except the Transco capacity, under the operation of the Fuel Management Agreement, VPEM can effectively control even that Transco capacity. With respect to all of VPSE's capacity, whether VPEM is explicitly in control or not, FERC rules with respect to "shipper must have title" mean that while VPSE is the shipper under the transport agreements, VPEM can get the benefit of these agreements through a series of "Buy-Sell" arrangements with VPSE. Under such arrangements, VPEM would buy gas at receipt points into Transco, then sell that same gas to VPSE before the gas goes into the Transco line, then VPSE transports gas it now

[7] And continuing through Jan of 2017.
[8] This 3 Bcf of storage capacity comes with 42,500 Dthd of withdrawal capacity able to feed DTI and Transco transport agreements.
[9] This is directly evidenced by the designation of VPEM as Agent in the filings by the interstate pipelines of their Index of Customers' listings.
[10] This is in addition to using DTI to fill the DTI storage.

holds the title for to the delivery point(s) under the Transco Agreement(s) then sells this gas at the delivery point(s) back to VPEM which then can either use the gas for VPEM generation or sell the gas to other downstream party(ies) at the delivery point(s). Just this sort of arrangement is explicitly contemplated by VPSE/VPEM/DVP as set forth in Attachment B of DVP's "Transaction Summary – Affiliate Transactions" as filed with the VSCC.

Q. Please continue.

A. The significance of this arrangement is that it would enable the Virginia SCC to require that VPEM/VPSE only transact with the Company at prices (inclusive of transportation to the Transco Zone 5 delivery points to the Company) that are equal to the lower of market or cost, and most significantly, fix the metric for "market", as the Company has done in the IRP, namely at the published Transco Zone 5 price on the day of the sale. And moreover, it would permit the Company ratepayers to not be burdened by capacity held by VPSE and controlled (or controllable by VPEM) which capacity is not utilized to generate electricity for the Company ratepayers. In short, the Virginia SCC should impose two requirements on the Company. First, it should require the Company to pay VPSE or VPEM for gas at "the lower of market or cost" through any capacity it holds or controls. Second, the SCC should not allow the Company to pay VPSE for any capacity that VPSE holds which is not directly utilized to generate electricity at the Company's plants. Effectively, this means that VPSE/VPEM would recover fixed reservation costs only to the extent the All-In Cost of Gas at the point(s) where the gas leaves the interstate market (whether it be via ACP or other routes) did not exceed the Transco Zone 5 Price.

Q. Can you please explain your logic here?

A. Certainly. In essence, if you look at the totality of the 2017 IRP, the Fuel Management Agreement, and the inclusion in the Company model of the costs of the ACP[11], the Dominion family of companies[12] (which is a mixture of federally regulated, state regulated and unregulated entities) have made a bet, backed by Virginia electric ratepayers, that having the ACP capacity is and will be better than just buying gas at Transco Zone 5 prices.

My recommendation is that the Virginia SCC should protect Virginia ratepayers with respect to this bet. They could do this by ensuring that the only costs Virginia ratepayers will bear are those costs that, on an All-In Cost of Gas basis, do not exceed what Virginia ratepayers would pay the Company if their gas for generation of electricity was purchased at Transco Zone 5 prices. In this way, the Virginia SCC gives the Dominion family the latitude to make investments and arrangements with regulated and unregulated affiliates and non-affiliates alike but requires that the Dominion family bear the risks of those investments and arrangements, not Virginia ratepayers.

Q. You mention all these regulated and unregulated affiliates. Are you suggesting inappropriate behavior?

A. No, that's not the point of my testimony. What I am suggesting is that, bottom line, it's about the tension between what is best for ratepayers and what is best for shareholders and how to assure that this tension and the possibility for erring on the side of

[11] *See* ER 6-18(a) where DOM includes "[T]he expected gas firm transportation service costs for the ACP pipeline . . . in row 9 (Virginia jurisdictional cost) of the sheet "1 _Fuel Backup" starting in the 2018/ 19 fuel year.").
[12] Dominion Resources, DTI, DOM VA, VPSE, and VPEM.

shareholders can and should be mitigated. One way to mitigate that tension is to protect Virginia ratepayers through this first possible mechanism I suggest.

Keep in mind, that under the Fuel Management Agreement, while the Company has appointed VPSE as its exclusive Fuel Manager, and VPEM manages both the VPSE capacity and sales to VPSE of gas, VPEM is not exclusive to VPSE (or the Company), and VPEM can use the capacity it holds or controls to make other sales as it sees fit. Given that fact, the Company (and its ratepayers) should not be on the hook to pay for any reserved capacity the Company does not directly get the beneficial use of (*i.e.,* directly benefits by means of daily delivered quantities); and when they do get the beneficial use of that capacity and the Fuel Management Agreement arrangements; that they should be protected. As mentioned above, the way to do this is for the Virginia SCC to require that the Company keep track of all Transco Zone 5 prices by day and pay to VPSE for gas the Company gets from VPSE that price (*i.e.,* the market price) every such day; and ***<u>not that "market price" plus fixed reservation costs</u>***. This mechanism, if adopted by the Virginia SCC would shift the risk of reserved capacity (which reserved capacity may or may not result in lower prices, as the Dominion family has asserted), off of the Company (and its ratepayers) and on to VPEM/VPSE and the rest of the Dominion family where it belongs.

Q. You said there were two mitigation mechanisms. What is the other?

A. The other mitigation mechanism would, with respect to the benchmarking against Transco Zone 5 Prices, operate similarly. The difference would be that the Virginia SCC would reduce the flow through to ratepayers of the difference between actual All-In Cost of Gas and what the cost of gas would have been based upon the Transco Zone 5 prices by the amount of return paid to ACP in rates paid by VPSE through rates until the Company ratepayers were kept whole on any difference in fuel costs.

Q. How would the Virginia SCC know what the return component of the rates paid to ACP would be?

A. If VPSE is paying the rates presented in Exhibit P of the ACP application, then approximately 75% of the ACP initial rate is made up of return. So, 75% of the amount paid by VPSE, would be the pot of dollars from which the "make whole" funds would be comprised. Then, once ratepayers were kept whole, the balance would no longer be credited to ratepayer fuel costs.

Q. What if VPSE is paying a lower rate, as a Foundation Shipper, as you discussed above?

A. In that event, I would have the return component of the ACP rate reduced by the difference between the dollars paid through the rate actually paid by VPSE to ACP and what the return component would have been at the Exhibit P rates. In short, the difference in dollars is taken "off the top" of the total return dollars that would be paid under the Exhibit P rates.

Q. Why do you take the difference in dollars paid under the two rates "off the top"?

A. Because, when a pipeline gives a discount, the effect on them is to reduce their return, assuming all other costs represent out-of-pocket cash costs or non-cash costs like depreciation.

Q. Have you modeled a pro forma pot of dollars that would result from this type of mechanism?

A. Yes. I introduced this concept into the model I developed showing the net cost of ACP (owing to the projected Price Spread) that I discussed above.

Q. What was the result?

A. In all four cases (the same as those discussed above) the modeled return exceeded the net cost of ACP by between $151 Million and $183 Million; meaning that the pot of dollars over the 20 Years of the contract associated with this modeled set of returns was sufficient to mitigate the modeled net cost to ratepayers and still provide the Dominion family with between $151 Million and $183 Million of profit.

Q. Does that conclude your testimony?

A. Yes.

Lander

Exhibits 1-3

Exhibit ER-1

Regional Pipelines and DOM VA Electric Generation Facilities

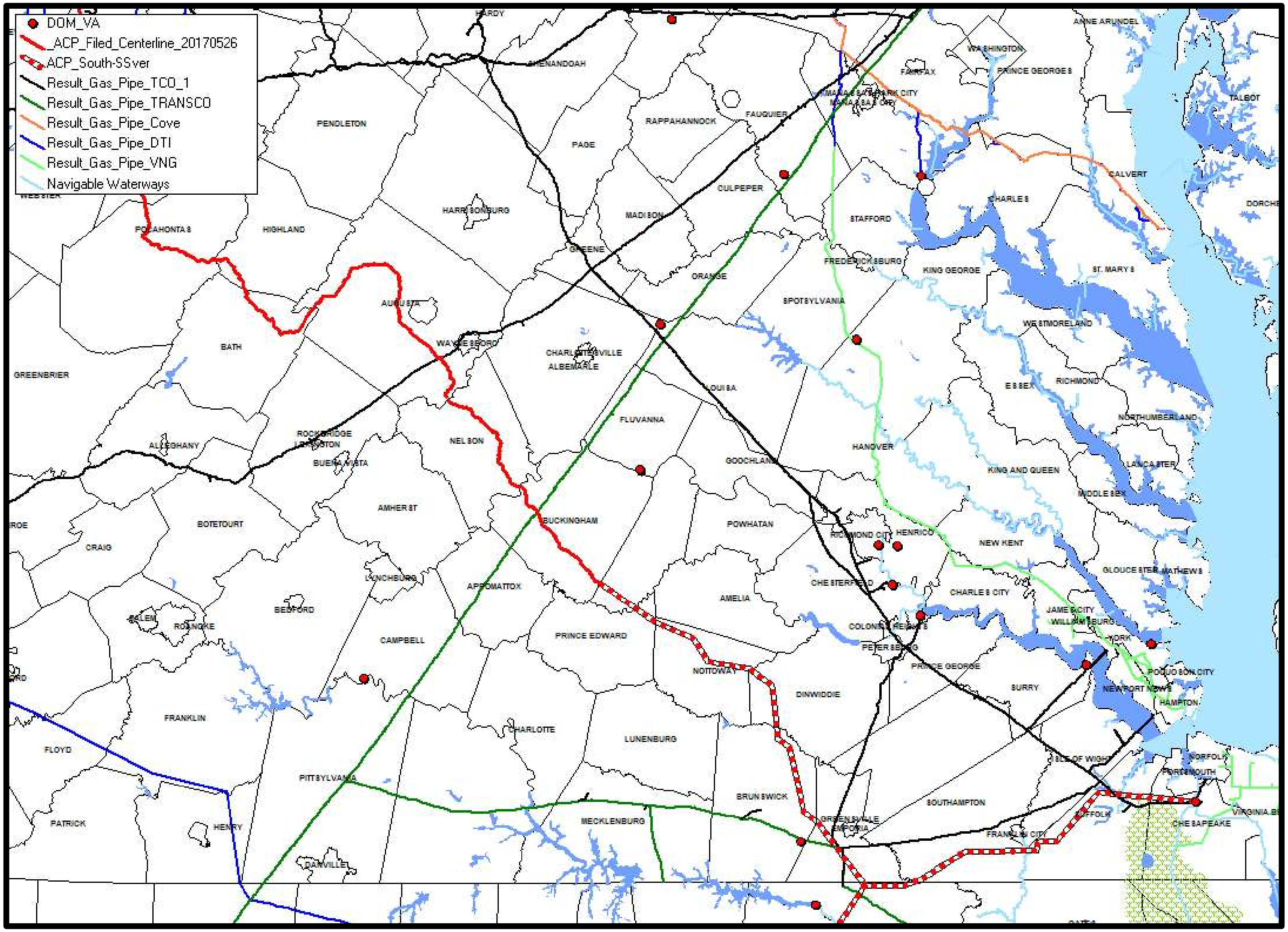


Exhibit Lander-2

Miles to ACP From DOM VA Natural Gas-Fired Power Plants

Attachment ER Set 3-7 (DEH) with Skipping Stone added Columns A, F, G & H

A Count	B Power Station	C Pipeline / LDC	D Upstream Pipeline Delivery Point	E Delivery Point	F County	G State	H Miles to ACP
1	Possum Point	Cove Point Pipeline	N/A	Possum Point	Prince William	VA	100+
2	Yorktown	Virginia Natural Gas	DTI Quantico/VNG	Yorktown	York	VA	30+
3	TCO - Chesterfield	Columbia Gas of Virginia	TCO Meter #831082	Chesterfield	Chesterfield	VA	31+
4	Gravel Neck	Columbia Gas of Virginia	TCO Meter #831081	Gravel Neck	Surry	VA	25+
5	Bellemeade	City of Richmond	TCO Meter #837059	Bellemeade	Richmond City	VA	35+
6	Gordonsville	Columbia Gas of Virginia	TCO Meter #833866	Gordonsville	Louisa	VA	40+
7	Eliz River	Columbia Gas of Virginia	TCO Meter #833469	Elizabeth River	Chesapeake	VA	~1
8	Darbytown	Virginia Natural Gas	DTI Quantico/VNG	Mechanicsville	Henrico	VA	37+
9	DTI-Chesterfield	Virginia Natural Gas	DTI Quantico/VNG	Mechanicsville	Chesterfield	VA	31+
10	Ladysmith	Virginia Natural Gas	DTI Quantico/VNG	Ladysmith	Spotsylvania	VA	68+
11	Remington	Columbia Gas of Virginia	Transco Remington/CGV	Remington	Fauquier	VA	78+
12	Altavista	Columbia Gas of Virginia	Transco Lynchburg/CGV	Altavista	Campbell	VA	47+
13	Hopewell	Columbia Gas of Virginia	TCO Market Area 1-33/CGV	Hopewell	Hopewell	VA	32+
14	Rosemary	Piedmont Natural Gas	Transco Panda Energy Meter #7319	Rosemary	Halifax	NC	5+
15	Bear Garden	Columbia Gas of Virginia	Transco Bear Garden/CGV	Bear Garden	Buckingham	VA	21+
16	Bremo	Columbia Gas of Virginia	Transco Bear Garden/CGV	Bremo	Fluvanna	VA	21+
17	Warren County	Columbia Gas Transmission	N/A	Warren County #842564	Warren	VA	72+
18	Brunswick County	Transcontinental Gas Pipe Line Company, LLC	N/A	Brunswick County #9008686	Brunswick	VA	6+

Exhibit Lander-3 (a)

Iteration 123 - with Maximum Exhibit P Rates and Periodic Rates Cases

Calculation of Net Cost to DOM VA Ratepayers using Basis Iteration 123 in IRP Model and Maximum Exhibit P ACP Rates

VPSE rate Pd to ACP "Price Spread": $ 1.75

Subscription in ACP (Dthd): 300,000

Portion of Rate pd that is Return: 75%

Iteration	Year	AvgOf DomSP	AvgOf TranscoZ5	Value of ACP ($/Dthd)	Cost of ACP ($/Dthd)	Net Cost of ACP/Dthd	300,000	Annual Contract Cost to Ratepayers 1/	Value of return to DOM Assumes 5 year Rate Cases	
123	2017	($1.21)	$0.70	$1.91						
123	2018	($0.81)	$0.26	$1.07						
123	2019	($0.58)	$0.09	$0.67	$1.75	$1.08	$118,314,392	$191,625,000	$143,718,750	
123	2020	($0.44)	$0.45	$0.89	$1.75	$0.86	$93,830,897	$191,625,000	$143,718,750	
123	2021	($0.79)	$0.11	$0.90	$1.75	$0.85	$93,053,987	$191,625,000	$143,718,750	
123	2022	($0.75)	($0.10)	$0.65	$1.75	$1.10	$120,105,456	$191,625,000	$143,718,750	
123	2023	($0.71)	($0.33)	$0.38	$1.75	$1.37	$150,329,909	$191,625,000	$143,718,750	
123	2024	($0.73)	($0.52)	$0.21	$1.58	$1.37	$149,538,122	$172,462,500	$129,346,875	
123	2025	($0.82)	($0.36)	$0.46	$1.58	$1.12	$122,490,566	$172,462,500	$129,346,875	
123	2026	($0.73)	($0.32)	$0.40	$1.58	$1.17	$128,179,693	$172,462,500	$129,346,875	
123	2027	($0.88)	($0.60)	$0.28	$1.58	$1.30	$142,310,712	$172,462,500	$129,346,875	
123	2028	($0.86)	($0.38)	$0.48	$1.58	$1.09	$119,509,190	$172,462,500	$129,346,875	
123	2029	($0.79)	($0.73)	$0.06	$1.42	$1.36	$148,681,352	$155,216,250	$116,412,188	
123	2030	($0.78)	($0.49)	$0.29	$1.42	$1.12	$123,154,453	$155,216,250	$116,412,188	
123	2031	($0.75)	($0.43)	$0.33	$1.42	$1.09	$119,288,293	$155,216,250	$116,412,188	
123	2032	($0.78)	($0.06)	$0.72	$1.42	$0.70	$76,238,817	$155,216,250	$116,412,188	
123	2033	($0.77)	($0.25)	$0.52	$1.42	$0.90	$98,396,684	$155,216,250	$116,412,188	
123	2034	($0.69)	($0.35)	$0.35	$1.28	$0.93	$101,492,900	$139,694,625	$104,770,969	
123	2035	($0.73)	($0.30)	$0.43	$1.28	$0.85	$92,798,360	$139,694,625	$104,770,969	
123	2036	($0.69)	($0.38)	$0.31	$1.28	$0.97	$105,747,743	$139,694,625	$104,770,969	
123	2037	($0.69)	($0.18)	$0.51	$1.28	$0.76	$83,367,643	$139,694,625	$104,770,969	
123	2038	($0.85)	($0.49)	$0.35	$1.28	$0.92	$100,856,165	$139,694,625	$104,770,969	
123	2039	($0.73)	($0.47)	$0.25						
123	2040	($0.80)	($0.30)	$0.49						
123	2041	($0.79)	($0.53)	$0.26						
123	2042	($0.76)	($0.70)	$0.06						
Over 20 Years of ACP		($0.74)	($0.28)	$0.46	$1.50	$1.04	$2,287,685,333	$3,294,991,875	$2,471,243,906	$183,558,573
				Avg Delta to DOM SP	Avg 20Year levelized cost	Avg 20 Net Cost of ACP	Net Cost of ACP to Ratepayers over 20 Year Contract	Total Rate Payer Cost	Total value of return on 300,000 Dthd of Capacity	Est'd Return Left over after Ratepayer Keep Whole

Exhibit Lander-3 (b)

Iteration 123 - with Typical Foundation Shipper Rates and Periodic Rates Cases

Calculation of Net Cost to DOM VA Ratepayers using Basis Iteration 123 in IRP Model and Estimated Foundation Shipper ACP Rates

VPSE rate Pd to ACP $ 1.40

Iteration	Year	AvgOf DomSP	AvgOf TranscoZ5	"Price Spread" Value of ACP ($/Dthd)	Cost of ACP ($/Dthd)	Net Cost of ACP/Dthd	Subscription in ACP (Dthd) 300,000	Annual Contract Cost to Ratepayers 1/	Value of return to DOM Assumes 5 year Rate Cases	
123	2017	($1.21)	$0.70	$1.91						
123	2018	($0.81)	$0.26	$1.07						
123	2019	($0.58)	$0.09	$0.67	$1.40	$0.73	$79,989,392	$153,300,000	$105,393,750	
123	2020	($0.44)	$0.45	$0.89	$1.40	$0.51	$55,505,897	$153,300,000	$105,393,750	
123	2021	($0.79)	$0.11	$0.90	$1.40	$0.50	$54,728,987	$153,300,000	$105,393,750	
123	2022	($0.75)	($0.10)	$0.65	$1.40	$0.75	$81,780,456	$153,300,000	$105,393,750	
123	2023	($0.71)	($0.33)	$0.38	$1.40	$1.02	$112,004,909	$153,300,000	$105,393,750	
123	2024	($0.73)	($0.52)	$0.21	$1.26	$1.05	$115,045,622	$137,970,000	$94,854,375	
123	2025	($0.82)	($0.36)	$0.46	$1.26	$0.80	$87,998,066	$137,970,000	$94,854,375	
123	2026	($0.73)	($0.32)	$0.40	$1.26	$0.86	$93,687,193	$137,970,000	$94,854,375	
123	2027	($0.88)	($0.60)	$0.28	$1.26	$0.98	$107,818,212	$137,970,000	$94,854,375	
123	2028	($0.86)	($0.38)	$0.48	$1.26	$0.78	$85,016,690	$137,970,000	$94,854,375	
123	2029	($0.79)	($0.73)	$0.06	$1.13	$1.07	$117,638,102	$124,173,000	$85,368,938	
123	2030	($0.78)	($0.49)	$0.29	$1.13	$0.84	$92,111,203	$124,173,000	$85,368,938	
123	2031	($0.75)	($0.43)	$0.33	$1.13	$0.81	$88,245,043	$124,173,000	$85,368,938	
123	2032	($0.78)	($0.06)	$0.72	$1.13	$0.41	$45,195,567	$124,173,000	$85,368,938	
123	2033	($0.77)	($0.25)	$0.52	$1.13	$0.62	$67,353,434	$124,173,000	$85,368,938	
123	2034	($0.69)	($0.35)	$0.35	$1.02	$0.67	$73,553,975	$111,755,700	$76,832,044	
123	2035	($0.73)	($0.30)	$0.43	$1.02	$0.59	$64,859,435	$111,755,700	$76,832,044	
123	2036	($0.69)	($0.38)	$0.31	$1.02	$0.71	$77,808,818	$111,755,700	$76,832,044	
123	2037	($0.69)	($0.18)	$0.51	$1.02	$0.51	$55,428,718	$111,755,700	$76,832,044	
123	2038	($0.85)	($0.49)	$0.35	$1.02	$0.67	$72,917,240	$111,755,700	$76,832,044	
123	2039	($0.73)	($0.47)	$0.25						
123	2040	($0.80)	($0.30)	$0.49						
123	2041	($0.79)	($0.53)	$0.26						
123	2042	($0.76)	($0.70)	$0.06						
Over 20 Years of ACP		($0.74)	($0.28)	$0.46	$1.20	$0.74	$1,628,686,958	$2,635,993,500	$1,812,245,531	$183,558,573
				Avg Delta to DOM SP	Avg 20Year levelized cost	Avg 20 Net Cost of ACP	Net Cost of ACP to Ratepayers over 20 Year Contract	Total Rate Payer Cost	Total value of return on 300,000 Dthd of Capacity	Est'd Return Left over after Ratepayer Keep Whole

Exhibit Lander-3 (c)

Average of All 200 Iterations with Maximum Exhibit P Rates and Periodic Rates Cases

Calculation of Net Cost to DOM VA Ratepayers using of 200 Basis Iterations in IRP Model and Maximum Exhibit P ACP Rates

VPSE rate Pd to ACP: $ 1.75

Portion of Rate pd that is Return: 75%

Year	AvgOf AvgOf DomSP	AvgOf AvgOf TranscoZ5	"Price Spread" Value of ACP	Cost of ACP	Net Cost of ACP	Subscription in ACP (Dthd) 300,000	Annual Contract Cost to Ratepayers	Value of return to DOM	
2017	($1.14)	$0.64	$1.78						
2018	($0.74)	$0.60	$1.34						
2019	($0.52)	$0.35	$0.87	$1.75	$0.88	$96,772,448	$191,625,000	$143,718,750	
2020	($0.55)	$0.00	$0.56	$1.75	$1.19	$130,620,350	$191,625,000	$143,718,750	
2021	($0.64)	($0.10)	$0.54	$1.75	$1.21	$132,399,471	$191,625,000	$143,718,750	
2022	($0.69)	($0.19)	$0.50	$1.75	$1.25	$137,044,641	$191,625,000	$143,718,750	
2023	($0.77)	($0.36)	$0.41	$1.75	$1.34	$146,617,682	$191,625,000	$143,718,750	
2024	($0.75)	($0.37)	$0.37	$1.58	$1.20	$131,477,833	$172,462,500	$129,346,875	
2025	($0.76)	($0.39)	$0.37	$1.58	$1.21	$132,201,601	$172,462,500	$129,346,875	
2026	($0.75)	($0.38)	$0.38	$1.58	$1.20	$131,309,524	$172,462,500	$129,346,875	
2027	($0.82)	($0.48)	$0.34	$1.58	$1.24	$135,471,671	$172,462,500	$129,346,875	
2028	($0.84)	($0.48)	$0.36	$1.58	$1.21	$132,941,240	$172,462,500	$129,346,875	
2029	($0.81)	($0.42)	$0.39	$1.42	$1.03	$112,406,284	$155,216,250	$116,412,188	
2030	($0.79)	($0.40)	$0.39	$1.42	$1.03	$112,613,476	$155,216,250	$116,412,188	
2031	($0.76)	($0.36)	$0.40	$1.42	$1.02	$111,866,887	$155,216,250	$116,412,188	
2032	($0.75)	($0.33)	$0.42	$1.42	$1.00	$109,471,659	$155,216,250	$116,412,188	
2033	($0.73)	($0.32)	$0.41	$1.42	$1.01	$110,153,626	$155,216,250	$116,412,188	
2034	($0.72)	($0.26)	$0.46	$1.28	$0.82	$89,467,973	$139,694,625	$104,770,969	
2035	($0.71)	($0.26)	$0.44	$1.28	$0.83	$91,148,310	$139,694,625	$104,770,969	
2036	($0.72)	($0.29)	$0.44	$1.28	$0.84	$92,002,722	$139,694,625	$104,770,969	
2037	($0.73)	($0.30)	$0.43	$1.28	$0.84	$92,262,820	$139,694,625	$104,770,969	
2038	($0.73)	($0.29)	$0.44	$1.28	$0.84	$91,720,577	$139,694,625	$104,770,969	
2039	($0.73)	($0.28)	$0.45						
2040	($0.73)	($0.30)	$0.43						
2041	($0.73)	($0.30)	$0.44						
2042	($0.72)	($0.31)	$0.42						
Over 20 Years of ACP	($0.73)	($0.28)	$0.45	$1.50	$1.06	$2,319,970,794	$3,294,991,875	$2,471,243,906	$151,273,112
			Avg Delta to DOM SP	Avg 20Year levelized cost	Avg 20 Net Cost of ACP	Net Cost of ACP to Ratepayers over 20 Year Contract	Total Rate Payer Cost	Total value of return on 300,000 Dthd of Capacity	Est'd Return Left over after Ratepayer Keep Whole

Exhibit Lander-3 (d)

Average of All 200 Iterations - with Typical Foundation Shipper Rates and Periodic Rates Cases

Calculation of Net Cost to DOM VA Ratepayers using Average of 200 Basis Iterations in IRP Model and Estimated Foundation Shipper ACP Rates

VPSE rate Pd to ACP $ 1.40

Year	AvgOf AvgOf DomSP	AvgOf AvgOf TranscoZ5	"Price Spread" Value of ACP	Cost of ACP	Net Cost of ACP	Subscription in ACP (Dthd) 300,000	Annual Contract Cost to Ratepayers	Value of return to DOM	
2017	($1.14)	$0.64	$1.78						
2018	($0.74)	$0.60	$1.34						
2019	($0.52)	$0.35	$0.87	$1.40	$0.53	$58,447,448	$153,300,000	$105,393,750	
2020	($0.55)	$0.00	$0.56	$1.40	$0.84	$92,295,350	$153,300,000	$105,393,750	
2021	($0.64)	($0.10)	$0.54	$1.40	$0.86	$94,074,471	$153,300,000	$105,393,750	
2022	($0.69)	($0.19)	$0.50	$1.40	$0.90	$98,719,641	$153,300,000	$105,393,750	
2023	($0.77)	($0.36)	$0.41	$1.40	$0.99	$108,292,682	$153,300,000	$105,393,750	
2024	($0.75)	($0.37)	$0.37	$1.26	$0.89	$96,985,333	$137,970,000	$94,854,375	
2025	($0.76)	($0.39)	$0.37	$1.26	$0.89	$97,709,101	$137,970,000	$94,854,375	
2026	($0.75)	($0.38)	$0.38	$1.26	$0.88	$96,817,024	$137,970,000	$94,854,375	
2027	($0.82)	($0.48)	$0.34	$1.26	$0.92	$100,979,171	$137,970,000	$94,854,375	
2028	($0.84)	($0.48)	$0.36	$1.26	$0.90	$98,448,740	$137,970,000	$94,854,375	
2029	($0.81)	($0.42)	$0.39	$1.13	$0.74	$81,363,034	$124,173,000	$85,368,938	
2030	($0.79)	($0.40)	$0.39	$1.13	$0.74	$81,570,226	$124,173,000	$85,368,938	
2031	($0.76)	($0.36)	$0.40	$1.13	$0.74	$80,823,637	$124,173,000	$85,368,938	
2032	($0.75)	($0.33)	$0.42	$1.13	$0.72	$78,428,409	$124,173,000	$85,368,938	
2033	($0.73)	($0.32)	$0.41	$1.13	$0.72	$79,110,376	$124,173,000	$85,368,938	
2034	($0.72)	($0.26)	$0.46	$1.02	$0.56	$61,529,048	$111,755,700	$76,832,044	
2035	($0.71)	($0.26)	$0.44	$1.02	$0.58	$63,209,385	$111,755,700	$76,832,044	
2036	($0.72)	($0.29)	$0.44	$1.02	$0.59	$64,063,797	$111,755,700	$76,832,044	
2037	($0.73)	($0.30)	$0.43	$1.02	$0.59	$64,323,895	$111,755,700	$76,832,044	
2038	($0.73)	($0.29)	$0.44	$1.02	$0.58	$63,781,652	$111,755,700	$76,832,044	
2039	($0.73)	($0.28)	$0.45						
2040	($0.73)	($0.30)	$0.43						
2041	($0.73)	($0.30)	$0.44						
2042	($0.72)	($0.31)	$0.42						
Over 20 Years of ACP	($0.73)	($0.28)	$0.45	$1.20	$0.76	$1,660,972,419	$2,635,993,500	$1,812,245,531	$151,273,112
			Avg Delta to DOM SP	Avg 20Year levelized cost	Avg 20 Net Cost of ACP	Net Cost of ACP to Ratepayers over 20 Year Contract	Total Rate Payer Cost	Total value of return on 300,000 Dthd of Capacity	Est'd Return Left over after Ratepayer Keep Whole

Lander

Discovery Responses

Virginia Electric and Power Company
Case No. PUR-2017-00051
Environmental Respondents
First Set

The following response to Question No. 1 of the First Set of Interrogatories and Requests for Production of Documents Propounded by the Environmental Respondents received on June 8, 2017 has been prepared under my supervision.

Karim Siamer
Lead Economist,
Load Research and Forecast
Dominion Energy Services, Inc.

Question No. 1

Reference page 18 of the IRP which states that the Company uses two econometric models with an end-use orientation to forecast sales, energy and peak demand.

a) Provide full documentation for both models.

b) Provide all inputs, assumptions, equations, and/or variables used in running both models in developing the Company's 2017 load forecast.

c) Provide all statistics from estimation of these econometric models.

d) Identify the time period used for the weather data in the first stage of the system model.

Response:

a) See Attachment ER Set 1-1(a) for the requested model documentation.

b) See Confidential Attachment ER Set 1-1(b) for the requested information, including confidential model inputs. Confidential Attachment ER Set 1-1(b) contains confidential information as designated therein by yellow highlighting and is being provided pursuant to the protections set forth in 5 VAC 5-20-170 and subject to the Hearing Examiner's Protective Ruling entered on June 14, 2017 in Case No. PUR-2017-00051, and any subsequent Protective Order or Protective Ruling that may be issued for confidential or extraordinarily sensitive information in this proceeding, and pursuant to Agreements to Adhere executed pursuant to any such rulings or orders.

c) See Attachment ER Set 1-1(c) and Attachment ER Set 1-1 (c) Peak and Energy Model Coefficients and Statistics. See also the Company's response to subpart (b) of Question No. 14 of this set

d) The time period used for the weather data was 1986 to 2015.

Dominion Energy

Electric Load Forecast Models Documentation

June 2017

1.1 Dominion Electric Load Forecast Models

1.1.1 Overview

This document discusses Dominion's Electric Load Forecast Models as developed and maintained by the Company. Electric load forecasting should be viewed as the use of a collection of separate but interrelated models along with an extensive process for data management, model estimation, and forecasting. The objective of the modeling process s is to produce reliable long-term forecasts of generation level Dominion Zone ("DOM Zone") and Dominion Load Serving Entity ("DOM LSE") monthly and seasonal peak demands, and monthly energy demands together with an hourly system load shape. In conjunction with system level forecasts, the modeling process also produces a corresponding forecast of monthly energy sales by customer class.

To accomplish this objective, the Company uses two primary econometric models with an end-use orientation:

- An Electric Sales Model, which is a customer class billing month model (described in Section 5.1) used to forecast energy sales for six major classes of customers
- An Electric Peak and Energy Model, which is an hourly load model (described in Section 6.1) used to forecast seasonal and monthly peaks and monthly energies at the system level

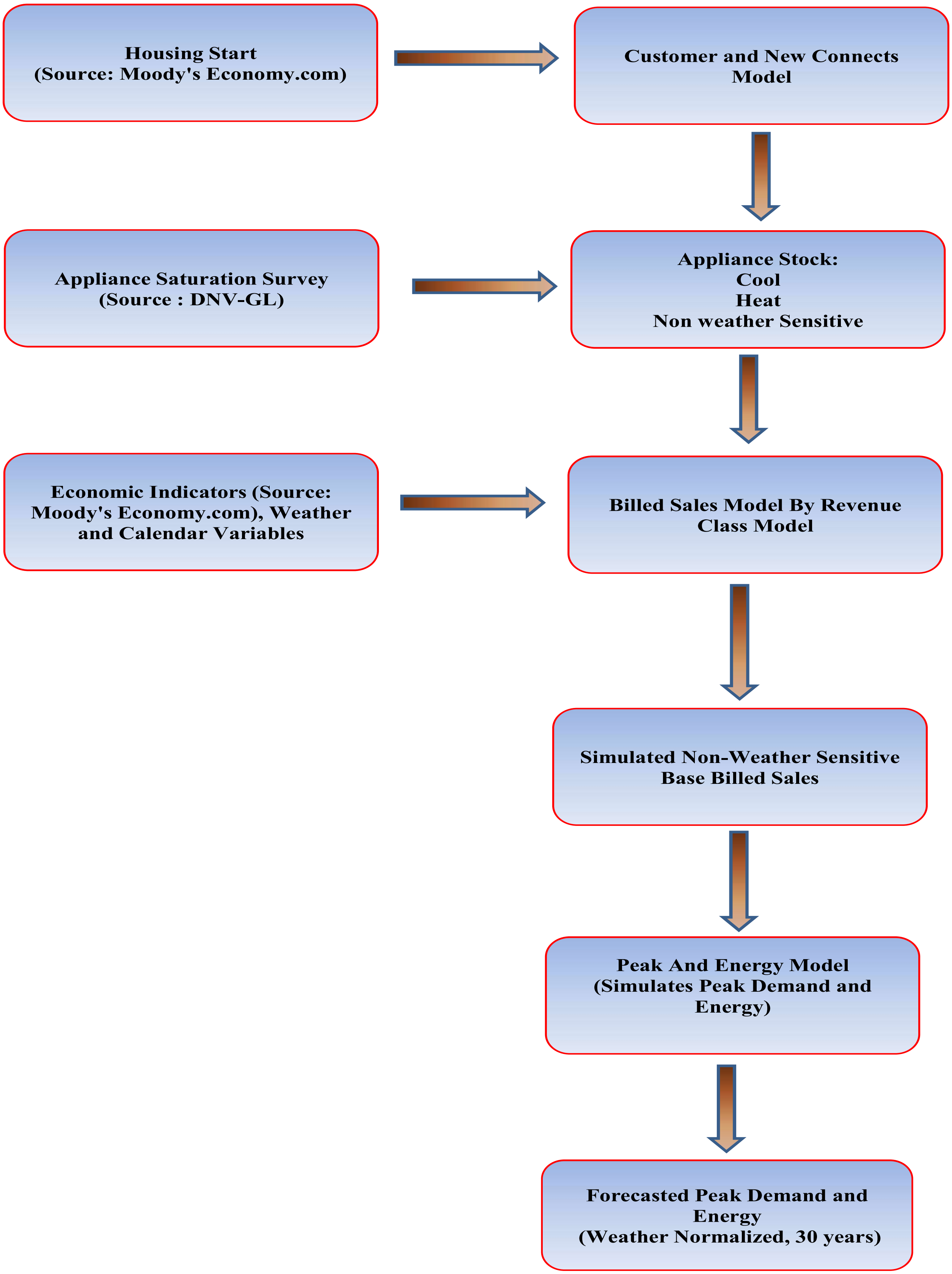
Both models are comprised of a set of individual regression equations that are dependent on supplemental models that provide forecasts of customer counts, end-use appliance stock energy intensities and saturations that are used in both primary econometric models. The Sales Model and the Peak and Energy Model also share in their specifications a rich set of weather constructs as well as economic, and demographic explanatory variables. The supplemental models and weather related constructs are described in Section 2.1 of this document.

The forecast of aggregate monthly energy produced by the Electric Sales Model is reconciled with system level monthly energy from the Electric Peak and Energy Model on a calendar month basis through a process of estimating monthly losses and unbilled sales as described in Section 7.1.

This integrated set of models and process steps used to produce the Company's electric load forecasts have been developed, enhanced, and re-estimated annually for over 20 years and have produced substantially consistent forecasts on a year to year basis.

A high-level schematic overview of the Dominion Load Forecasting process is shown in Figure 1.1.1.1.

Figure 1.1.1.1 – Dominion Electric Load Forecasting Process



2.1 Customer Count and New Connects Forecast Model

The Customer Count and New Connects Model forecasts customer counts for the residential, commercial, and Public Authority revenue classes. The forecasted customer counts are then used in the Electric Sales Model as right-hand side variables in developing the corresponding class sales forecast.

2.1.1 Residential Customer Count Model

Described below is the two stage approach used to produce the final forecast the number of residential customers from the forecast of housing starts sourced from Moody's Economy.com.

2.1.1.1 Residential New Connect Equation

The Residential New Connect Equation functionally relates the number of monthly residential customer new connects to monthly number of residential housing starts on a lagged moving average basis. Once the coefficients are estimated, the equation is then used to forecast annual residential new connects based on Moody's Economy.com forecast of housing starts.

Specification:

$$\text{CONRESTL} = \text{RESTL0} + \text{VAHS} * \text{L2VAHSTL} + \left(\sum_{i=2}^{12} \text{RESM}_i * \text{M}_i \right) + \text{HREC} * \text{VAHRECESSION}$$

Where:

CONRESTL = Monthly moving average of annual historical residential new connects

Coefficients:

RESTL0 = Regression intercept term

VAHS = Marginal effect of lagged moving average housing starts on moving average residential new connects

RESM_i = Calendar month shape effects for month i, for i = 2 to12

HREC = Marginal effect of a housing recession affecting Virginia

Explanatory Variables:

L2VAHSTL = Historical moving average number of annual residential housing starts lagged two months. Projected housing starts provided by Moody's Economy.com are used in forecast mode.

M_i = 1 if month = i, zero otherwise for i = 2 to12

VAHRECESSION = Recession indicator variable (May 2006 – Jan 2011 = 1, 0 otherwise)

2.1.1.2 Residential Customer Count Equation

Since there is usually not a one-to-one correspondence between the number of residential customers, i.e., the number of accounts, and the number of new connects, the residential customer count equation functionally relates the historical observed moving average number of customers to the number of new connects on a moving average basis. Once the coefficients of this equation are estimated, it is applied to the forecasted new connects from the Residential New Connect equation to produce the final forecast of residential customers.

Specification:

CONRESAJ = CUSRES0 + RECRES * IDREC + NEWCON * CONRESTL

Where:

CONRESAJ = Moving average sum of residential customers

Coefficients:

CUSRES0 = Regression intercept term
RECRES = Marginal effect of a housing recession affecting Virginia
NEWCON = Marginal effect of residential new connects on the number of residential accounts

Explanatory Variables:

IDREC = Indicator variable for the period of housing recession (May 2006 through Jan 2011)
CONRESTL = Annualized historical moving average of new connects in the estimation period, predicted new connects from the residential new connect equation in forecast mode.

2.1.2 Commercial Customer Count Model

The forecast of the number of commercial class customers is based on its historical relationship to the lagged change in the residential customer count.

Specification:

CUSCOMAJ = ADJCUSC + LAG(CUSCOMAJ) + CUSC0 + ($\sum_{i=2}^{12} CUSC\mathrm{M}_i * \mathrm{M}_i$) * DIF(CUSRESAJ) + CUSC1 * LAG(DIF(CUSRESAJ)) + DUM4 * (DATE < '01JUN2002')

Where:

CUSCOMAJ = Count of commercial customers

Coefficients:

CUSC0 = Regression intercept term
$\mathrm{CUSCM_i}$ = Calendar month shape affect for month i, for i = 2 to12

CUSC1 = Marginal effect of lagged change in the number of residential customers
DUM4 = Offset for customers counts prior to June 2002.

Explanatory Variables:

ADJCUSC = Adjustment for known incremental new large commercial customers in the forecast period
LAG(CUSCOMAJ) = One period lag in the number of commercial customers
M_i = 1 if month = i, zero otherwise for i = 2 to12
LAG(DIF(CUSRESAJ)) = One period lag in the change in the number of residential customers (Section 2.1.1)
DUM4 = Indicator variable (Date < June 2002) = 1, 0 otherwise)

2.1.3 Public Authority Customer Count Model

The forecast of Public Authority customers is based on its historical relationship to the forecasted change in the residential customer count from the residential customer count model and the change in the 5-year moving average forecast of government employment (State, Local, and Federal) for the Commonwealth of Virginia sources from Moody's Economy.com.

Specification:

CUSPUBAJ = ADJCUSP + ALPHA* LAG(CUSPUBAJ) + CUSP0 + ($\sum_{i=1}^{11} CUSP\mathrm{M}_i * \mathrm{M}_i$) * DIF(CUSRESAJ) + CUSP1 * LAG(DIF(CUSRESAJ)) + CUSP2 * DIF(VAEGOV60) + DUM5 * (DATE < '01MAY2000')

Where:

CUSPUBAJ = Count of commercial customers

Coefficients:

CUSP0 = Regression intercept term

$\mathrm{CUSPM_i}$ = Calendar month shape affect for month i, for i = 1 to11
CUSP1 = Marginal effect of lagged change in the number of residential customers
CUSP2 = Sensitivity of Public Authority sales to the change in the 5 year moving average in Government Employment
DUM5 = Offset for customers counts prior to May 2000.

Explanatory Variables:

ADJCUSP = Adjustment for known incremental new Public Authority customers in the forecast period
LAG(CUSPUBAJ) = One period lag in the number of Public Authority customers
M_i = 1 if month = i, zero otherwise for i = 1 to11

LAG(DIF(CUSRESAJ)) = One period lag in the change in the number of residential customers (Section 2.1.1)

DIF(VAEGOV60) = One period change in 5 year moving average in Government Employment (Commonwealth of VA + Local + Federal) on a historical basis in the estimation period and from Moody's Economy.com forecast in the forecast period.

(DATE < '01MAY2000') = Indicator variable (Date < MAY 2000) = 1, 0 otherwise)

3.1 Appliance Stock Variable Development

This section describes the representation of a key driver of electric demand, the stock of electric appliances in use by residential customers. For this purpose three main categories of appliance stocks are recognized with the corresponding name of the regression construct shown in parenthesis:

- Cooling Appliances (**STOCKAC**): Heat pump cooling, central air units, window units, and dehumidifiers
- Heating Appliances (**STOCKHT**): Heat pump heating, resistance space heating, and furnace fans
- Non-Weather Sensitive Base Appliances (**STOCKNW**): Dishwasher, dryer, refrigerator, water heater, TV, electric range, electric lighting

Average total annual kWh usage for each end-use is conceptualized as a function of three primary parameters as follows:

Appliance Usage = Saturation * Energy Intensity * Customer Count

Where:

Saturation = % of residential customers using the appliance

Energy Intensity = Annual kWh usage per appliance

Customer Count = Historical residential customer count in the estimation period, forecasted residential customers from the Customer Count Model in the forecast period.

The Company uses current and historical appliance saturation and intensity data acquired from surveys of its own residential customers. The two most recent surveys were conducted in 2013 and 2016 on behalf of the Company by DNV-GL. From the raw survey results the consultant estimates, through a conditional demand analysis, the electric intensity for each appliance as well as the associated level of appliance saturation. A summary of appliance intensity estimates from each of the past three appliance surveys is presented in Figure 3.1.1.

Figure 3.1.1 - Residential Appliance Intensities

	2008	2013 DNV GL	2016 DNV GL
Appliance	**Intensities (kWh)**		
Clothes dryers	688	754	742
Clothes washers	383	360	280
Dishwashers	569	260	243
Freezer	1,098	1,097	729
Second Freezer			449
Refrigerators	1,058	968	785
Second Refrigerator			922
Electric ranges	922	679	894
Water heaters	3,782	3,370	3,473
Televisions	652	519	440
Set-Top Box			247
DVD			35
Desktop			426
Laptop			61
Other Electronics			583
HT			
Base Resistance Space Heating			2,802
Furnace fans.			1,030
Heat Pump Heating	2,447	2,447	3,703
AC			
Window Air	1,297	*1,459*	1,721
Heat Pump cooling	2,529	2,447	2,400
Central Air	2,447	2,263	2,955
Dehumidifier			810
Ligthing (2.6 hours/day)			
Incand.			111
CFL			22
LED			6

The results of a 2008 survey, conducted by the Company, were assumed to apply to stocks in historical years up to and including 2014. The results of the 2013 survey applied to stocks through 2015, while the most recent survey results applied to appliance stocks in 2016 and in subsequent forecast years.

On a going forward basis, it is assumed that through technological improvements, changes in industry standards and stock turnover, each major appliance will exhibit progressive improvement in efficiency as well as changes in the saturation. Figure 3.1.2 graphically presents the assumed trajectories for appliance efficiency and intensity over time for heat pumps and refrigerators.

Figure 3.1.2 - Residential Space Conditioning and Refrigeration Intensity

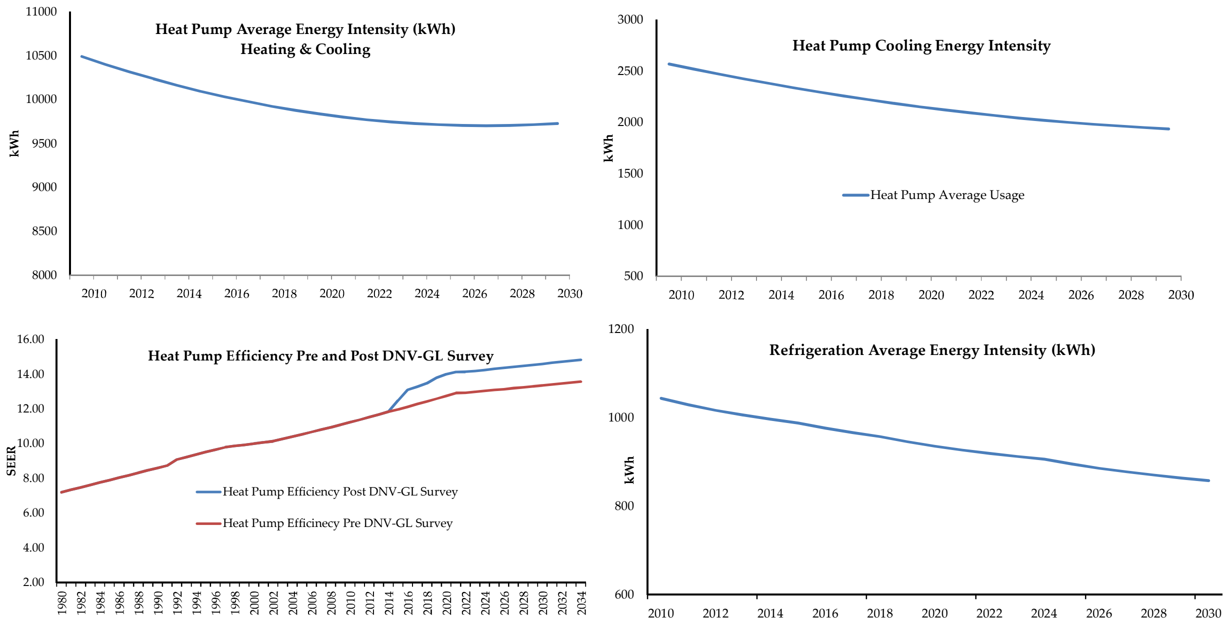
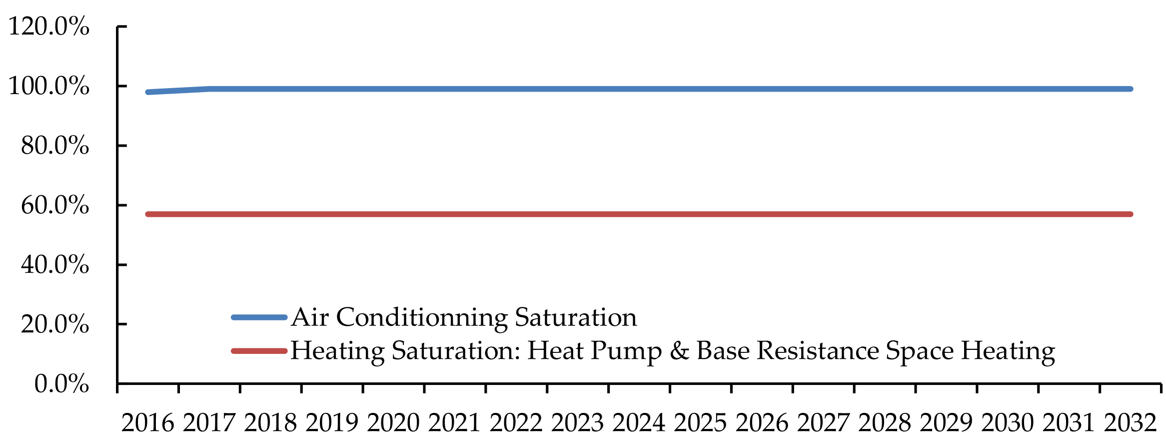


Figure 3.1.3 displays the long term yearly saturations assumed for these major appliances.

Figure 3.1.3 - Space Conditioning Equipment Saturation



Note that the most recent DNV-GL survey conducted in 2016 provided additional detail for non-weather sensitive appliances such as second refrigerators and freezers, consumer electronics, and lighting not available in previous surveys. Of particular significance is that the 2016 survey yielded new information on the usage and penetration associated with compact fluorescent and LED lighting alternatives to standard incandescent lighting. This formed the basis for the projected continued reduction in energy intensity for the lighting end-use owing to the cessation of standard incandescent light bulb production and increasing penetration of the highly efficient CFL and LED lights. The long term projected intensity and penetration projected for the lighting end-use is shown in Figures 3.1.4 and 3.1.5.

Figure 3.1.4 - Residential Lighting Intensity

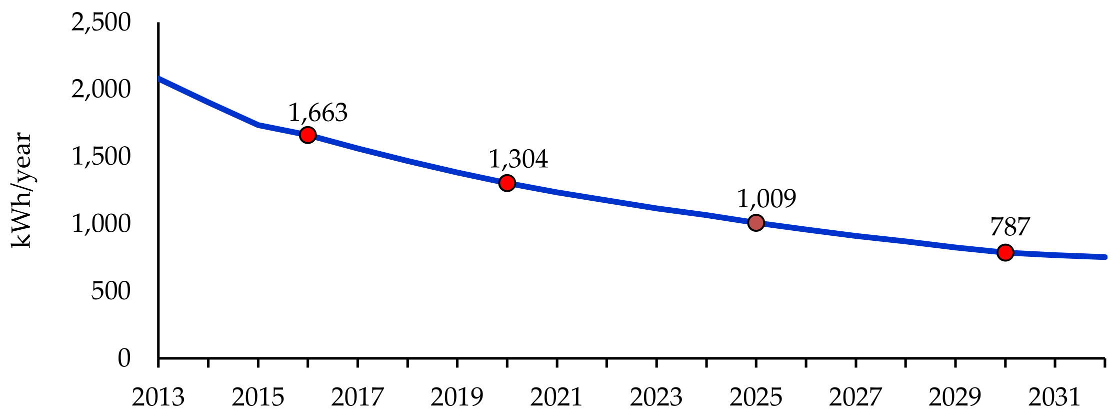
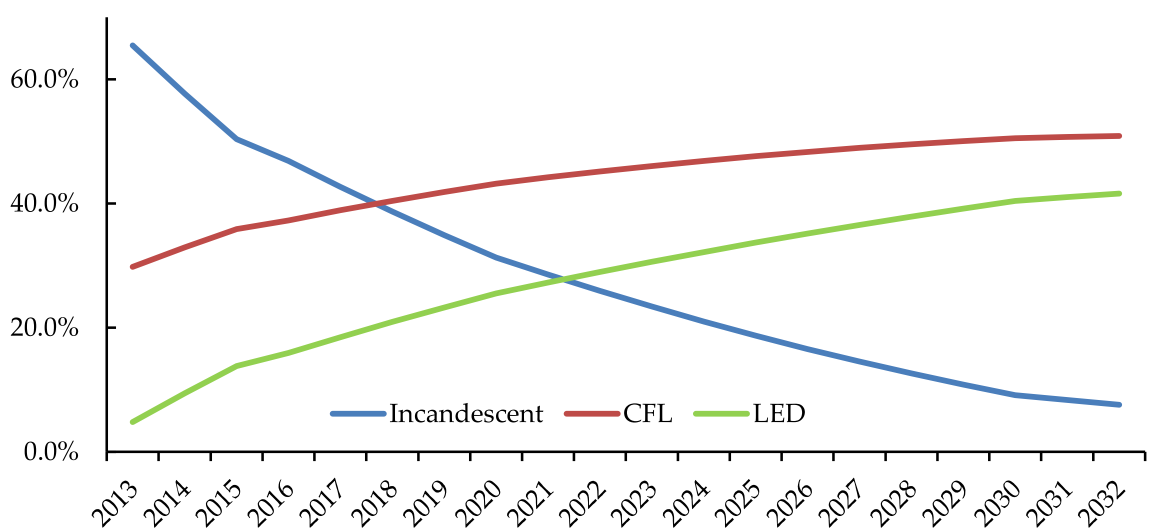


Figure 3.1.5 - Residential Lighting Saturation



The intensity and saturation assumptions for each appliance were then consolidated into the three principal appliance stock categories which, when applied to historical and projected customer counts, form each of the three respective end-use regression variables. Figure 3.1.6 provides an example calculation of the values for the three constructs applicable to the year 2018.

Figure 3.1.6 – Appliance Stock Explanatory Variable Calculation

		Year	Residential Customer Count	Intensity	Saturation	Total (GWh)
STOCKAC	**Cooling Equipment**	**2018**	**2,341,375**	2,641	96%	5,935,484
STOCKHT	**Heating Equipment**			3,035	42%	2,984,551
STOCKNW	**Base**			8,810	100%	20,627,514
	Total			**14,486**		**29,547,549**

As explanatory variables in the Energy Sales equations, values for STOCKAC, STOCKHT, and STOCKNW were expressed on an average per billing day basis.

4.1 Weather Construct Variable Development

Given the significant influence of weather on electric demand, a rich set of weather related regression constructs are specified in both the Energy Sales and the Peak and Energy models. These regression constructs address the multidimensional and non-linear nature of seasonal weather across the large geographic region encompassed by the DOM Zone.

In the specification of the monthly level Sales Model, the two principal weather constructs are expressed as a cooling season regression model, nominally labeled **WHOT**, and a heating season regression model, nominally labeled **WCOLD**. Each model is based on four key underlying weather variables: temperature, humidity, wind speed, and cloud cover. For the Sales Model each construct enters the equations as additional monthly level weather-related regression variables. In the hourly level Peak and Energy model, the individual constituent components that make up the WHOT and WCOLD regression models are explicitly included on an hourly basis.

Hourly historical values for the four principal weather variables are used as recorded by weather stations at five cities within the DOM Zone: Richmond, Norfolk, Washington D.C., Roanoke, and Raleigh, N.C. A composite weather variable that expresses the combined effect of both temperature and humidity is the Temperature Humidity Index ("THI") and is calculated at each weather station as:

THI&city = Temperature&city + 0.40*(Humidity&city/100-0.50)*max(Temperature&city - 57,0)

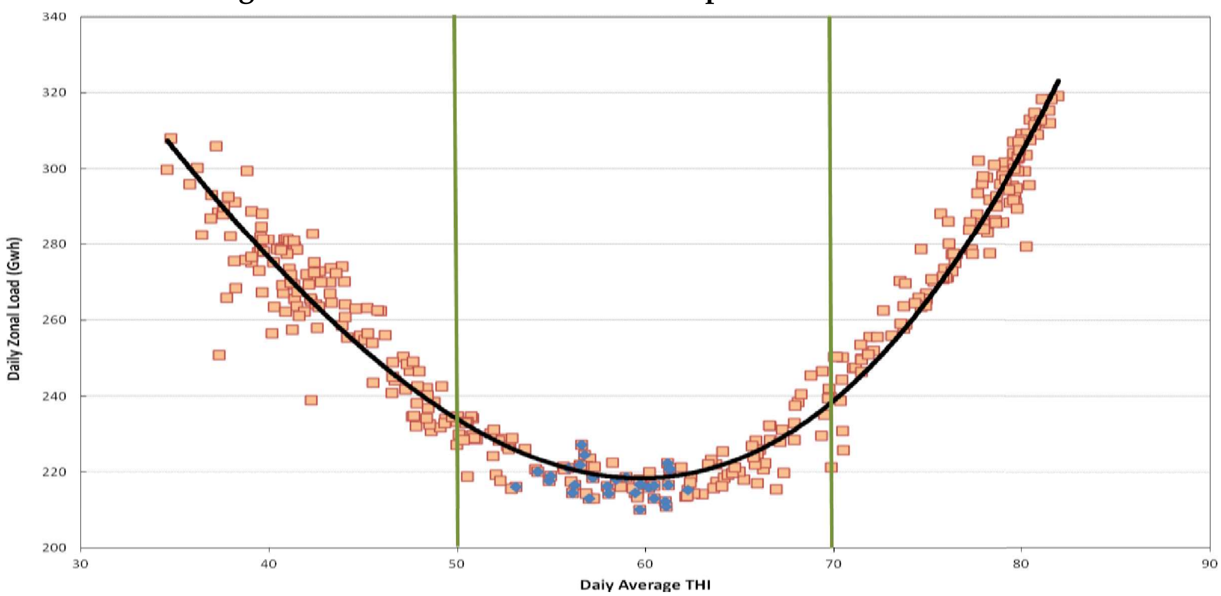
Where:

&City= Richmond (**ri**), Norfolk (**no**), Washington-DC (**wa**), Roanoke (**ro**), or Raleigh (**ra**)

Given the non-linear relationship between electric demand and THI, as depicted in Figure 4.1.1.1, the full range of THI values in each season is split into intervals so as to represent a regression spline for each weather station. A weighted averaging of the spline sections over all weather stations and then over the seasonal ranges become the cooling and heating spline variables. Weighted lagged values of these spline segments, as well as their interaction with wind speed, cloud cover, and weekend variables, form the full final set of composite weather-related explanatory variables used in the Sales Model equations. The derivation of each weather regression construct as a function of component weather variables is detailed below for each season.

It should be noted that in the Sales Model equations there appear two versions of the WHOT and WCOLD regression equations. In the case of customer classes billed on a cyclical basis, the THI values used are first calculated as weighted averages over the billing cycles that make up each billing month. This is done so as to better align weather with billed sales. Thus for the residential, commercial, industrial, and Public Authority classes, the billing cycle weighted versions of the right-hand side variables in WHOT and WCOLD regression constructs are used and the constructs are labeled as WHOTBIL and WCOLDBIL, respectively. In the case of the Wholesale customer entities, which are billed on a calendar month basis, a calendar month version of the right-hand side weather variables are used and the regression constructs are labeled WHOTCAL and WCOLDCAL, respectively.

Figure 4.1.1 - Non-Linear Relationship Between Load and THI



4.1.1 Cooling Season Weather Construct (WHOT) Derivation

1) CDD65&city = Max(THI&city-65,0)
2) CDD70&city = Max(THI&city-70,0)
3) CDD75&city = Max(THI&city-75,0)
4) CDD80&city = Max(THI&city-80,0)
5) CDD65 = 0.2375*CDD65**no** + 0.2375*CDD65**ri** + 0.2375*CDD65**wa** + 0.2375*CDD65**ro** + 0.05*CDD65**ra**
6) CDD70 = 0.2375*CDD70**no** + 0.2375*CDD70**ri** + 0.2375*CDD70**wa** + 0.2375*CDD70**ro** + 0.05*CDD70**ra**
7) CDD75 = 0.2375*CDD75**no** + 0.2375*CDD75**ri** + 0.2375*CDD75**wa** + 0.2375*CDD75**ro** + 0.05*CDD75**ra**
8) CDD80 = 0.2375*CDD80**no** + 0.2375*CDD80**ri** + 0.2375*CDD80**wa** + 0.2375*CDD80**ro** + 0.05*CDD80**ra**

9) CDDSpline = 0.449*CDD65 + 0.313*CDD70 + 0.120*CDD75 + 0.118*CDD80
10) LAGCDD = 0.75*LAG(CDDSpline) + 0.25*LAG2(CDDSpline)

Explanatory:

In the Sales Model, LAG() is a one month lag operator, LAG2() is a two month lag operator. In the Peak and Energy Model, LAG() is a one hour lag operator, LAG2() is a two hour lag operator.

Seasonal (0,1) Indicator Variables:

WINTER = DECEMBER + JANUARY + FEBRUARY
SPRING = MARCH + APRIL
SUMMER = MAY + JUNE + JULY + AUGUST + SEPTEMBER
FALL = OCTOBER + NOVEMBER

11) CDDSplineSummer = CDDSpline * Summer (0,1 indicator)
12) CDDSplineSpring = CDDSpline * Spring (0,1 indicator)
13) CDDSplineFall = CDDSpline * Fall (0,1 indicator)
14) HotWind = (Min(CDD60,15)/15)*Wind Speed (miles/hour)
15) HotClouds= (Min(CDD60,15)/15)*Sky Cover Index (0,10)
16) CDDWeekend = CDDSpline*WeekkEnd (0,1 indicator variable)
17) **WHOT**= α*LagCDD+β*CDDSplineSummer+γ*CDDSplineSpring+δ*CDDSplineFall +ε*HotWind+θ*HotClouds+ϑ*CDDWeekEnd

Where:

$\alpha,\beta,\gamma,\delta,\varepsilon,\theta$ and ϑ are coefficients estimated through the Sales Model regression.

4.1.2 Heating Season Weather Construct (WCOLD) Derivation

1) HDD35&city. = Max(35-THI&city,0)
2) HDD45&city. = Max(45-THI&city,0)
3) HDD55&city. = Max(55-THI&city,0)
4) HDD60&city. = Max(60-THI&city,0)
5) HDD35 = 0.2375*HDD35**no** + 0.2375*HDD35**ri** + 0.2375*HDD35**wa** + 0.2375*HDD35**ro** + 0.05*HDD35**ra**
6) HDD45 = 0.2375*HDD45**no** + 0.2375*HDD45**ri** + 0.2375*HDD45**wa** + 0.2375*HDD45**ro** + 0.05*HDD45**ra**
7) HDD55 = 0.2375*HDD55**no** + 0.2375*HDD55**ri** + 0.2375*HDD55**wa** + 0.2375*HDD55**ro** + 0.05*HDD55**ra**
8) HDD60 = 0.2375*HDD60**no** + 0.2375*HDD60**ri** + 0.2375*HDD60**wa** + 0.2375*HDD60**ro** + 0.05*HDD60**ra**
9) HDDSpline = 0.132*HDD60 + 0.458*HDD55 + 0.303*HDD45 + 0.108*HDD35
10) LAGHDD = 0.75*LAG(HDDSpline) + 0.25*LAG2(HDDSpline)
11) ColdWind = (Min(HDD60,20)/20)*Wind Speed
12) ColdClouds = (Min(HDD60,20)/20)*Sky Cover Index
13) HDDWknd = HDDSpline*WeekEnd
14) **WCOLD** = α*LagHDD+β*HDDSpline+γ*HDDWeekEnd+δ*ColdWind+ ε*ColdCloud

Where:

$\alpha,\beta,\gamma,\delta,\varepsilon$ are coefficients estimated through the Sales Model regression.

5.1 Electric Sales Model

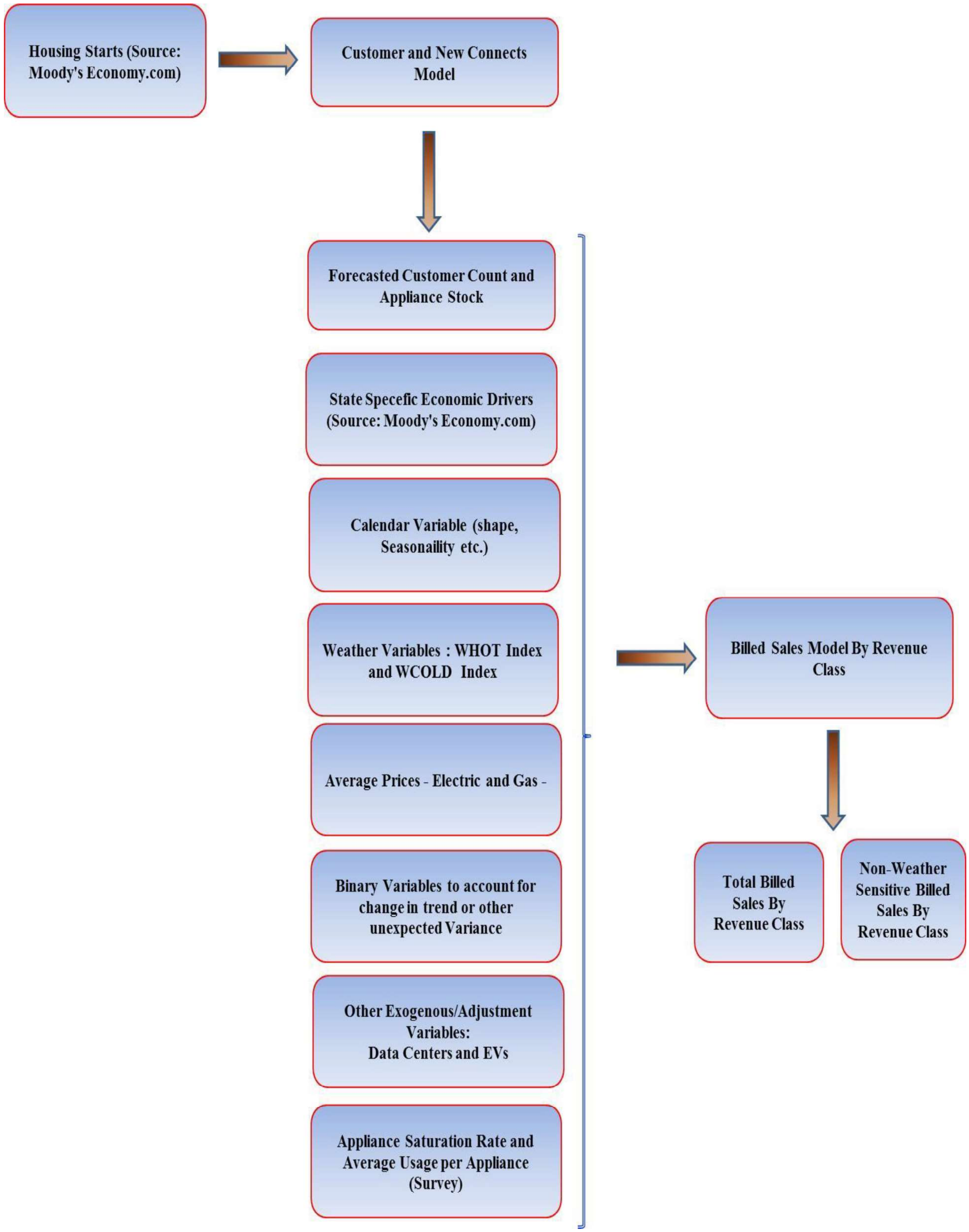
5.1.1 Overview

The Electric Sales Model incorporates separately estimated sales equations that model monthly billed sales for each of 6 principal revenue classes. The sectors are:

1) Residential
2) Commercial
3) Industrial
4) Public Authority
5) Street and Traffic Lighting
6) Wholesale (Sales for Resale) Customers (5 equations for 5 entities)

Aggregate billed sales for classes one through five constitute the total retail billed sales from DOM LSE customers. Each of the class sales equations are specified in a manner that produces estimates of total sector billed sales by billing month and, where appropriate, estimates of the associated aggregated regression effects for each of three categories of explanatory variables, namely, those related to heating, cooling, and non-weather sensitive trend, respectively. These constituent regression effects are referred to as "estimating equations". The sales model equations are estimated based on a rolling 30 years of historical monthly billing data for each class. A schematic representation of the Energy Sales forecasting process is shown in Figure 5.1.1.1.

Figure 5.1.1.1 Electric Sales Forecast Development



Preparation of the final retail sales forecast proceeds from a reconciliation of the forecasted DOM LSE monthly energy from the Peak and Energy Model with the forecasted retails sales from the Sales Model. The reconciliation process, described in the discussion of the Unbilled Sales Model, Section 7.1, of this document, involves both the calculation of losses as well as the billed and unbilled portions of monthly retail sales attributable to each calendar month.

The specifications for each class equation are described below.

5.1.2 Residential Sales Equation

The residential sales equation expresses observed total residential MWh sales (MWHRESAJ) in each historical billing period as a function of the sum (MWHRESHT) of three estimating equations which model the aggregate regression effects of:

1) Non-weather sensitive or base variables (MWHRBASE)
2) Weather sensitive cooling variables (MWHAIR)
3) Weather sensitive heating variables (MWHRHT)

In addition to the three estimating equations, the specification includes dummy variables to handle significant singular events and outliers followed by an autoregressive error term.

Specification:

MWHRESAJ = MWHRESHT + _RHORES1*ZLAG1 (MWHRESAJ – MWHRESHT)

With:

MWHRESHT = MWHRBASE + MWHRAIR + MWHRHT
+ _RESD1 * ((DATE='01JUN2003'D) + (DATE='01DEC2003'D) + .5*(DATE='01MAR2004'D))
+ _RESD2 * ((DATE='01JUL2005'D) - 0.3*(DATE='01AUG2005'D))
+ _RESD3 * (DATE='01JUL2006'D)
+ _RESD4 * (DATE='01JAN2011'D)
+ _RESD5 * (DATE>='01JAN2013'D)

Where:

MWHRESAJ = Billed sales by billing month; contains actual month billed sales in the estimation period and forecasted billing month sales in the forecast period
ZLAG1 () = One period lag operator on the difference (MWHRESAJ – MWHRESHT)
MWHRBASE = Estimating equation for non-weather sensitive residential sales
MWHRAIR = Estimating equation for weather sensitive residential sales from cooling demand
MWHRHT = Estimating equation for weather sensitive residential sales from heating demand
(DATE="DDMMMYYY"D) = (0,1) indicator variable for month specified

Coefficients:

_RHORES1 = Error term auto-regression coefficient
_RESD1, _RESD4 = To model high or low billed sales anomalies in the billing months specified
_RESD2, _RESD3 = To model, for the billing months specified, departures from typical July/August shape relationship since July sales are normally higher than August sales
_RESD5 = To model impact of the Federal Sequestration on residential sales beginning in 2013 and thereafter

5.1.3 Residential Estimating Equations

5.1.3.1 Non-Weather Sensitive Sales Equation

Specification:

MWHRBASE = _RESCONS * BDAYS + RESADJ
+ _RAPL * STOCKNW * BDAYS
+ _RAPLPR1 * STOCKNW *BDAYS * (L12R800/VAPIL12)
+ ($\sum_{i=2}^{12}$ _$M_i * M_i$) * STOCKNW * BDAYS
+ _RESREC*RECESSION

Where:

MWHRBASE = Regression component for non-weather sensitive residential sales in each billing period

Coefficients:

_RESCONS = Regression intercept term
_RAPL = Base contribution of the weighted stock of non-weather sensitive appliances (STOCKNW) per billing day
_RAPLPR1 = Marginal sensitivity of residential non-weather sensitive appliance demand to residential electricity prices relative to per capita personal income
_M_i = Billing month shape effect for billing month i, for i = 2 to12
_RESREC = Marginal effect of economic recessions

Explanatory Variables:

BDAYS = The average number of billing days per cycle per month
RESADJ = 0 in the estimation period. In the forecast period this represents block adjustments for projected future incremental sales from electric vehicles
STOCKNW = The weighted stock of non-weather sensitive appliance demand in MWh/day as determined from conditional demand analyses (Section 3.1);
L12R800 = 12-month moving average of real residential electricity prices ($/MWh)
VAPIL12 = 12-month lag of real disposable personal income per capita for Virginia ($)
M_i = 1 if month = i, zero otherwise for i = 2 to12

RECESSION = Indicator variable (0= not in economic recession, 1= in economic recession)

5.1.3.2 Weather Sensitive Cooling Sales Equation

Specification:

MWHRAIR = _RAIR * STOCKAC * WHOTBIL
+ _RAIRHOT * WHOTBIL
+ _RAIRUER * STOCKAC *WHOTBIL * VAUERD12
+ _RACPR2S * STOCKAC * WHOTBIL * PRESSUM
+ _RACPR2 * STOCKAC * WHOTBIL * LAGPRS

Where:

MWHRAIR = Regression component for weather sensitive residential sales from cooling demand in each billing period

Coefficients:

_RAIR = Base sensitivity of sales from air conditioning appliance stock (STOCKAC) to the billing cycle weighted average cooling construct (WHOTBIL)
_RAIRHOT = Marginal sensitivity of sales from cooling demand from the billing cycle weighted average cooling construct
_RAIRUER = Marginal sensitivity of sales from cooling to the VA unemployment rate
_RACPR2S = Marginal short-term sensitivity of cooling sales to real summer residential electricity prices
_RACPR2 = Marginal long-term sensitivity of cooling sales to real summer residential electricity prices

Explanatory variables:

STOCKAC = Weighted stock of air conditioning appliances in MWh/day (Section 3.1)
WHOTBIL = Cooling weather regression equation (Section 4.1)
VAUERD12 = 12-month moving average of the change in the VA unemployment rate (%)
PRESSUM = 12-month moving average of summer residential price of electricity (real $/MWh)
LAGPRS = 6-year moving average of real summer residential price of electricity (real $/MWh)

5.1.3.3 Weather Sensitive Heating Sales Equation

Specification:

MWHRHT = _RHT * STOCKHT * WCOLDBIL
+ _RHTCLD * WCOLDBIL
+ _RHTUER * STOCKHT * WCOLDBIL * VAUERD12
+ _RHTPR2S * STOCKHT * WCOLDBIL * RRSEWIN
+ _RHTPR2 * STOCKHT * WCOLDBIL * LAGPRW

Where:

MWHRHT = Regression component for weather sensitive residential sales from heating demand in each billing period

Coefficients:

_RHT = Base sensitivity of sales from heating appliance stock (STOCKHT) to the billing cycle weighted average heating construct (WCOLDBIL)
_RHTCLD = Marginal sensitivity of sales from heating demand to the billing cycle weighted average heating construct
_RAIRUER = Marginal sensitivity of sales from heating demand to the VA unemployment rate
_RHTPR2S = Marginal short-term sensitivity of heating sales to real winter residential electricity prices
_RHTPR2 = Marginal long-term sensitivity of heating sales to real winter residential electricity prices

Explanatory variables:

STOCKHT = Weighted stock of electric heating appliances in MWh/day (Section 3.1);
WCOLDBIL = Heating weather regression equation (Section 4.1);
VAUERD12 = 12-month moving average of the change in VA unemployment rate (%);
RRESWIN = 12-month moving average of winter residential price of electricity (real $/MWh);
LAGPRW = 6-year moving average of winter residential price of electricity (real $/MWh).

5.1.4 Commercial Sales Equation

The commercial sales equation expresses total commercial sector MWh sales (MWHCOMAJ) in each historical billing period as a function of the sum (MWHCOMHT) of three estimating equations which model the respective aggregate regression effects of:

1) Non-weather sensitive variables (MWHCBASE)
2) Weather sensitive cooling variables (MWHCAIR)
3) Weather sensitive heating variables (MWHCHEAT)

There is no available data on air conditioning or heating stock in this sector; however, the climate of Virginia is such that most commercial establishments do have air conditioning. Consequently, it is reasonable to assume that the growth in the air conditioning/heating stock is roughly proportional to the growth in commercial customers as measured in the CUSCOMA2 variable which serves as a proxy for electric HVAC equipment.

In addition to the three estimating equations, the specification includes dummy variables to handle significant singular events and outliers.

Specification:

MWHCOMAJ = MWHCOMHT

With:

MWHCOMHT = MWHCBASE + MWHCAIR + MWHCHEAT
+ _COMD1 * ((DATE='01JUN2003'D) + (DATE='01DEC2003'D))
+ _COMD2 * ((DATE<='01SEP1998'D))
+ _COMD3 * (DATE>='01AUG2004'D)
+ _COMD4 * (DATE='01JUL2005'D) – 0.3 * (DATE='01AUG2005'D))

Where:

MWHCOMAJ = Billed sales by billing month; contains actual month billed sales in the estimation period and forecasted billing month sales in the forecast period
MWHCBASE = Estimation equation for non-weather sensitive commercial sales
MWHCAIR = Estimation equation for weather sensitive commercial sales from cooling demand
MWHCRHEAT = Estimation equation for weather sensitive commercial sales from heating demand
(DATE="DDMMMYYY"D) = 0,1 indicator variable for month specified

Coefficients:

_COMD1, _COMD4 = To model high or low billed sales anomalies in the billing months specified
_COM2, _COMD3 = To model, for the billing months specified, departures from typical July/August shape relationship since July sales are normally higher than August sales;

5.1.5 Commercial Estimating Equations

5.1.5.1 Non-Weather Sensitive Sales Equation

Specification:

MWHCBASE = _COMCONS * BDAYS + COMADJ
+ (_COMEMP + _COMPRR1 * CPRICE60
+ ($\sum_{i=2}^{12}$_$\mathrm{CD}_i * \mathrm{M}_i$)) * VAGSP * BDAYS
+ _COMREC * RECESSION

Where:

MWHCBASE = Regression component for non-weather sensitive commercial sales regression effect in each billing period

Coefficients:

_COMCONS = Regression intercept term
_COMEMP = Sensitivity of commercial sales to the Virginia Gross State Product
_COMPPR1 = Sensitivity of commercial sales to the price of electricity for the commercial class and the Virginia Gross State Product
_CD2 to _CD12 = Billing month shape effect for billing month i, for i = 2 to12

_COMREC = Effect of economic recessions defined in the RECESSION indicator variables

Explanatory Variables:

BDAYS = The average number of billing days per cycle per month
COMADJ = 0 in the estimation period. In forecast period this represents a block load adjustments for future incremental commercial customers, e.g. firm future data center loads known to the Company plus forecasted incremental new data center loads based on a 2015 study prepared for the Company by Quanta Technology, LLC, entitled "Dominion Northern Virginia Load Forecast"
CPRICE60 = 60 month moving average of commercial class electricity price
M2 to M12 = 1 if month = i, zero otherwise for i = 2 to12
VAGSP = Historical real Virginia Gross State Product in billions $ in estimation period; Moody's Economy.com forecast in the forecast period.
RECESSION = Indicator variable (0= not in economic recession, 1= in economic recession)

5.1.5.2 Weather Sensitive Cooling Sales Equation

Specification:

MWHCAIR = (_COMHOTA + _COMHO96 * (DATE > '01JAN1996'D)
+ _COMHOTP * CSPRICE) * CUSCOMA2 * WHOTBIL

Where:

MWHCAIR = Regression component for weather sensitive commercial sales regression effect from cooling demand in each billing period

Coefficients:

_COMHOTA = Marginal sensitivity of sales from cooling demand from the billing cycle weighted average cooling construct (WHOTBIL) and moving average number of commercial customers
_COMHO96 = Marginal change in sensitivity to cooling construct post the Jan, 1996 billing period and the number of commercial customers
_COMHOTP = Sensitivity of sales to the average real commercial rate in the summer months and the number of commercial customers

Explanatory variables:

WHOTBIL = Cooling weather regression equation (Section 4.1);
CSPRICE = 60 month moving average of average real cents per kWh rate for the commercial class in the summer months
CUSCOMA2 = In the estimation period, the historical 60 day moving average number of commercial customers. In the forecast period the projected 60 day moving average is provided by the Commercial Customer Count Model described in Section 2.1.2;

5.1.5.3 Weather Sensitive Heating Sales Equation

Specification:

MWHCHEAT = (_COMCLDA + _COMCL96 * (DATE >= '01DEC1995'D)
+ _COMCLDP * CWPRICE) * CUSCOMA2 * WCOLDBIL;

Where:

MWHCHEAT = Regression component for weather sensitive commercial sales from heating demand in each billing period

Coefficients:

_COMCLDA = Marginal sensitivity of sales from heating demand from the billing cycle weighted average heating construct (WCOLDBIL) and the number of commercial customers;
_COMCL96 = Marginal change in sensitivity to cooling construct post the Dec, 1995 billing month and the number of commercial customers;
_COMCLDP = Sensitivity of sales to the ratio of the average real commercial electric rate to the average real gas price in the winter months and the number of commercial customers;

Explanatory variables:

WCOLDBIL = Heating weather regression equation (see section 4.1);
CWPRICE = Ratio of the 60 month moving average of average real cents per kWh commercial class electric price to the 60 month average real price of natural gas in the winter months,
CUSCOMA2 = In the estimation period, the historical 60 day moving average number of commercial customers. In the forecast period the projected 60 day moving average is provided by the Commercial Customer Count Model described in Section 2.1.2

5.1.6 Industrial Sales Equation

The industrial sales equation expresses observed total industrial sector MWh sales (MWHINDAJ) in each historical billing period as a function of the sum (MWHINDHT) of three estimating equations which model the respective aggregate regression effects of:

1) Non-weather sensitive variables (MWHIBASE)
2) Weather sensitive cooling variables (MWHIAIR)
3) Weather sensitive heating variables (MWHIHEAT)

In addition to the three estimating equations, the specification includes dummy variables to handle significant singular events and outliers.

Specification:

MWHINDAJ = MWHINDHT

With:

MWHINDHT = MWHIBASE + MWHIAIR + MWHIHEAT
+ (_INDD1 * ((DATE<'01Feb1994'D) + (DATE>'01JAN1997'D))
+ _INDD2 * ((DATE='01JUN2002'D) * 0.5 + (DATE='01JUN2003'D)
+ (DATE='01DEC2003'D) + (DATE='01NOV2003'D) * 0.5)
+_INDD3 * (DATE='01AUG2006'D)) * BDAYS

Where:

MWHIBASE = Estimation equation for non-weather sensitive industrial sales
MWHIAIR = Estimation equation for weather sensitive industrial sales from cooling demand
MWHIHEAT = Estimation equation for weather sensitive industrial sales from heating demand
(DATE="DDMMMYYYY"D) = (0,1) indicator variable for month specified

Coefficients:
_INDD1 = To model high or low billed sales anomalies in the billing months specified
_INDD2 = To model, for the billing months specified, departures from typical June shape
_INDD3 = To model, for the billing months specified, departures from typical October shape

5.1.7 Industrial Estimating Equations

5.1.7.1 Non-Weather Sensitive Sales Equation

Specification:

MWHIBASE = (_INDBDAY * BDAYS) + INDADJ
+ (_INDMEMP * VAEMAN * BDAYS)
+ (_INDRLPR * RELBILL5 * BDAYS)
+ ($\sum_{i=2}^{12}$ _IDX$_i$ $*$ M$_i$) * BDAYS
+ _INDREC * RECESSION

Where:

MWHIBASE = Regression component for non-weather sensitive industrial sales in each billing period

Coefficients:

_INDBDAY = Base industrial sales per billing day
_INDMEMP = Marginal per unit effect of manufacturing employment on industrial sales
_INDRLPR = Marginal sensitivity of industrial demand to the industrial class average rate

_IDXi = Billing month shape effect for month i, for i = 2 to12
_INDREC = Marginal effect of economic recessions specified in the RECESSION indicator variables

Explanatory Variables:

BDAYS = The average number of billing days per cycle per month
INDADJ = 0 in the estimation period. In forecast mode this represents block adjustments for known future incremental new industrial customers
M2 to M12 = 1 if month = i, zero otherwise for i = 2 to12
VAEMAN = Historical total Virginia manufacturing employment (000's) in the estimation period; Moody's Economy.com forecast in the forecast period.
RELBEL5 = 3 year moving average of the average price of electricity for an industrial customer
RECESSION = Indicator variable (0= not in economic recession, 1= in economic recession)

5.1.7.2 Weather Sensitive Cooling Sales Equation

Specification:

MWHIAIR = _INDHOTX * WHOTBIL

Where:

MWHIAIR = Regression component weather sensitive industrial sales from cooling demand in each billing period

Coefficients:

_INDHOTX = Marginal sensitivity of sales from cooling demand from the billing cycle weighted average cooling construct (WHOTBIL)

Explanatory variables:

WHOTBIL = Cooling weather regression equation (Section 4.1)

5.1.7.3 Weather Sensitive Heating Sales Equation

Specification:

MWHIHEAT = _INDCLDX * WCOLDBIL

Where:

MWHIHEAT = Estimated weather sensitive industrial sales from heating demand in each billing period

Coefficients:

_INDCLDX = Sensitivity of billed sales to the weighted system average heating construct

Explanatory variables:

WCOLDBIL = Heating weather regression equation (Section 4.1);

5.1.8 Public Authority Sales Equation

The Public Authority class includes the following governmental entities: Commonwealth of Virginia, Counties and Municipalities, Military Service, and NASA. The Public Authority sales equation expresses observed total MWh sales (MWHPUBAJ) in each historical billing period as a function of the sum (MWHPUBHT) of two estimating equations modeling the aggregate regression effects of:

1) Base, non-weather sensitive variables (MWHPBASE)
2) Weather sensitive variables (MWHPWEA)

In addition to the base and weather sensitive components, the specification includes dummy variables to handle significant singular events and outliers followed by an autoregressive error term.

Specification:

MWHPUBAJ = MWHPUBHT + _RHOPUB1 * ZLAG (MWHPUBAJ – MWHPUBHT)

With:

MWPUBHT = MWHPBASE + MWHPWEA
+ _PUBD1 * (DATE<'01JUN1996'D)
+ _PUBD2 * ((DATE='01NOV1996'D) + (DATE='01OCT1997'D))
+ _PUBD3 * (DATE='01JUN2003'D)
+ _PUBD4 * ('01OCT2000'D <= DATE <= '01MAY2002'D)

Where:

MWHPBASE = Estimation equation for non-weather sensitive public authority sales
MWHPWEA = Estimation equation for weather sensitive public authority sales from cooling demand
(DATE="DDMMMYYY"D) = (0,1) indicator variable for month specified
ZLAG () = One billing period lag operator on the difference (MWHPUBAJ – MWHPUBHT)

Coefficients:

_RHOPUB1 = Error term auto-regression coefficient
_PUBD1 = To model for the billing months specified, departures from typical June shape
_PUBD2 = To model, for the billing months specified, departures from typical October/November shape

_PUBD3 = To model, for the billing months specified, departures from typical June shape
_PUBD4 = To model, for the billing months specified, departures from typical shape

5.1.9 Public Authority Estimating Equations

5.1.9.1 Non-Weather Sensitive Sales Equation

Specification:

MWHPBASE = (_PUBBDAY * BDAYS) + PUBADJ
+ (($\sum_{i=2}^{12}$ _MP$_i$ $*$ M$_i$) * BDAYS)
+ (_PUBPR * AVPUBMA * BDAYS)
+ (_PUBCUS * CUSPUBA2 * BDAYS)
+ (_PUBEMML * MAEMPML * BDAYS)
+ _PUBREC * RECESSION

Where:

MWHPBASE = Regression component for non-weather sensitive public authority sales in each billing period.

Coefficients:

_PUBBDAY = Public Authority sales per billing day regression intercept term
_MP2 to _MP12 = Calendar month effect for billing month i, for i = 2 to12
_PUBPR = Marginal per billing day sensitivity to average real Public Authority price of electricity
_PUBCUS = Marginal sales per billing day per Public Authority account
_PUBEMML = Marginal effect of changes in total manufacturing employment
_PUBREC = Marginal effect of historical economic recessions

Explanatory Variables:

BDAYS = The average number of billing days per cycle per month
PUBADJ = 0 in the estimation period. In forecast mode this represents a block load adjustment for known future incremental public authority loads not accounted for in the estimating equation
M2 to M12 = 1 if month = i, zero otherwise for i = 2 to 12
AVPUBMA = 5 year moving average real public authority price of electricity
CUSPUBA2 = The historical number of Public Authority customers in the estimation period and the forecasted number of customers from the Public Authority Customer Count Model (Section 2.1.3) in the forecast period.
MAEMPML = Historical Total Manufacturing Employment (000's) in the estimation period; Moody's Economy.com forecast in the forecast period.
RECESSION = Indicator variable (0= not in economic recession, 1= in economic recession)

5.1.9.2 Weather Sensitive Sales Equation

Specification:

MWHPWEA = (_PUBHOT * WHOTBIL * CUSPUBA2 / 1000000)
+ (_PUBLCD * WCOLDBIL * CUSPUBA2 / 1000000)

Where:

MWHPWEA = Regression component for weather sensitive public authority sales from cooling and heating demand in each billing period

Coefficients:

_PUBHOT = Marginal sensitivity of sales from cooling demand from the billing cycle weighted average cooling construct
_PUBLCD = Marginal sensitivity of sales from cooling demand from the billing cycle weighted average cooling construct

Explanatory variables:

WHOTBIL = Cooling weather regression equation (Section 4.1)
WCOLDBIL = Heating weather regression equation (Section 4.1)
CUSPUBA2 = Average number of public authority customers scaled to millions (Section 2.1.3)

5.1.10 Street and Traffic Lighting

Sales in this sector are assumed to grow proportional to customers. The equation for street and traffic lighting is given by:

MWHSTLTL = _STLC + _STLCUS * CUSRESA2
+ ($\sum_{i=2}^{12}$ _$\mathrm{ST}_i * \mathrm{M}_i$) * (DATE > = '01JAN1990')

Where:

MWHSTLTL = Regression component non-weather sensitive residential sales in each billing period

Coefficients:

_STLC = Regression intercept term
_STLCUS = Marginal effect of changes in total number of residential customers
_ST_i = Calendar month effect for billing month i, for i = 2 to12

Explanatory Variables:

CUSRESA2 = Historical total number of residential customers (000's) in the estimation period; forecasted total number of residential customers from the Residential Customer Count Model (Section 2.1) in the forecast period
M_i = 1 if month = i, zero otherwise for i = 2 to12
(DATE > = '01JAN1990') = indicator variable (0= pre-01JAN1990, 1= post 01JAN1990)

5.1.11 Wholesale (Sales for Resale) Customer Equations

There are five resale customers within DOM Zone:

1) Old Dominion Electric Cooperative ("ODEC")
2) North Carolina Municipals
3) North Carolina Electric Membership Corporation
4) Virginia Municipal Electric Association No. 1
5) Other Virginia Cooperatives

Monthly sales for each wholesale entity are modeled by individual equations which include non-weather sensitive and weather sensitive components. Lack of detailed data on the number of final customers served by each entity and the economic conditions applicable to these final customers prevents the use of elaborate modeling techniques for this sector. However, given the geographic and economic proximity of these customers and their largely residential character, it is expected that usage patterns to not differ greatly between wholesale and Dominion's own retail customers. For this reason the approach used to forecast sales for resale is to assume proportionality to the DOM LSE residential class non-weather sensitive base sales regression component (MWHRBASE from the residential Sales Model relabeled as MWHZBASE) as the exogenous variable for the wholesale customer non-weather sensitive estimating equation. Likewise, wholesale customer heating and cooling estimating equation specifications use the STOCKHT and STOCKAC appliance stock exogenous variables from the residential class weather sensitive regression components.

The individual sales for resale equations for each of the five wholesale customers are identical except for the right-hand side dependent variable and entity specific indicator variables to handle singular events and outliers. Rather than describe the specification for each of the five individual wholesale customers, it is sufficient to document in full the specification for ODEC, the largest wholesale customer, as representative of each of the other Sales for Resale customer class equations.

The specification for ODEC is:

ODEC = MWHODECH + _RHOODC1*LAG(ODEC)

With:

MWHODECH = MWHOBASE + MWOAIR + MWHOHT
+ _ODCD1 * ((DATE='01OCT2007'D) - (DATE='01NOV2007'D))
+ _ODCD2 * (DATE< '01DEC2003'D)
+ _ODCD3 * ('01NOV1998'D < DATE < '01MAY2000'D)
+ _ODCD4 * ('01DEC2002'D < DATE < '01OCT2005'D)
+ _ODCD5 * (DATE = '01MAR2009'D)

Where:

MWHODECH = Billed sales by month; contains actual month billed sales in the estimation period and forecasted billing month sales in the forecast period
LAG() = One period lag operator
MWHOBASE = Estimating equation for non-weather sensitive ODEC sales
MWHOAIR = Estimating equation for weather sensitive ODEC sales from cooling demand
MWHOHT = Estimating equation for weather sensitive ODEC sales from heating demand
(DATE="DDMMMYYY"D) = (0,1) indicator variable for month or range of months specified

Coefficients:

_RHOODC1 = Error term auto-regression coefficient
_ODCD1 to _ODCD5 = To model high or low billed sales anomalies in the billing months specified

5.1.12 ODEC Estimating Equations

5.1.12.1 Non-Weather Sensitive Sales Equation

Specification:

MWHOBASE = _ODCCONS + RES1ADJ + (_ODCBASE +
+ ($\sum_{i=2}^{12} \_\mathrm{ODCM}_i * \mathrm{M}_i$)) * (NDAYS/BDAYS) * MWHZBASE

Where:

MWHZBASE = Regression component for non-weather sensitive ODEC sales in each billing period

Coefficients:

_ODCCONS = Regression intercept term
_ODCBASE = Base component of monthly non-weather sensitive ODEC sales
$\_\mathrm{M}_i$ = Calendar month shape effect for month i, for i = 2 to12

Explanatory Variables:

NDAYS = Number of days in the calendar month
BDAYS = The average number of billing days per cycle per month
RES1ADJ = 0 in the estimation period. In the forecast period this represents block adjustments for projected future incremental sales from electric vehicles within the ODEC system
MWHZBASE = The value of MWHRBASE from the residential non-weather sensitive estimating equation but without the RESADJ block load adjustments;
M_i = 1 if month = i, zero otherwise for i = 2 to12

5.1.12.2 Weather Sensitive Cooling Sales Equation

Specification:

MWHOAIR = (_ODCHOT + _ODCAIR * STOCKAC + _ODCPRS * STOCKAC*LAGPRS) * WHOTCAL

Where:

MWHOAIR = Regression component for weather sensitive ODEC sales from cooling demand in each month

Coefficients:

_ODCHOT = Base sales from cooling demand from the weighted calendar average cooling construct
_ODCAIR = Marginal sensitivity of sales from cooling demand from STOCKAC
_ODCPRS = Marginal short-term sensitivity of cooling sales to real summer residential electricity prices

Explanatory variables:

STOCKAC = Weighted stock of air conditioning appliances (Section 3.1)
LAGPRS = 6-year moving average of real summer residential price of electricity (real $/MWh)
WHOTCAL = In the estimation this expands to a system average weighted calendar month heating regression equation which includes eight coefficients (Section 4.1);

5.1.12.3 Weather Sensitive Heating Sales Equation

Specification:

MWHOHT = (_ODCCLD + _ODCHT * STOCKHT + _ODCPRW * STOCKHT*LAGPRW) * WCOLDCAL

Where:

MWHOHT = Regression component for weather sensitive ODEC sales from heating demand in each month

Coefficients:

_ODCCLD = Base sales from heating demand from the weighted calendar average cooling construct
_ODCHT = Marginal sensitivity of sales from heating demand represented in STOCKHT
_ODCPRS = Marginal short-term sensitivity of cooling sales to real summer residential electricity prices

Explanatory variables:

STOCKAC = Weighted stock of air conditioning appliances (Section 3.1)
LAGPRS = 6-year moving average of real summer residential price of electricity (real $/MWh)
WHOTCAL = Cooling weather regression equation (Section 4.1)

6.1 Electric Peak and Energy Model

6.1.1 Overview

The Electric Peak and Energy Model, also referred to as the "System Model" or "Area Output Model", is a collection of 24 individual regression equations, one for each hour of the day, which model aggregate unrestricted demand in the hour for the DOM Zone within PJM as a function of a detailed specification of weather constructs, end-use, economic, and calendar variables. The extensive set of weather constructs model interactions between both current and lagged values of temperature, humidity, wind speed, sky cover, and precipitation. The specification also includes the sum of all non-weather sensitive billed sales regression effects from the Sales Model to reflect the base level of hourly demand. In addition, the residential heating stock (STOCKHT) and cooling appliance stock (STOCKAC) variables are included to drive potential peak producing hourly loads. Finally, moving average electric prices, calendar, holiday, and indicator variables for outlier events complete the specifications. The dependent variable for each equation is the corresponding hour's actual loads over the past 30 years adjusted to add back historical load management reductions and behind the meter solar generation.

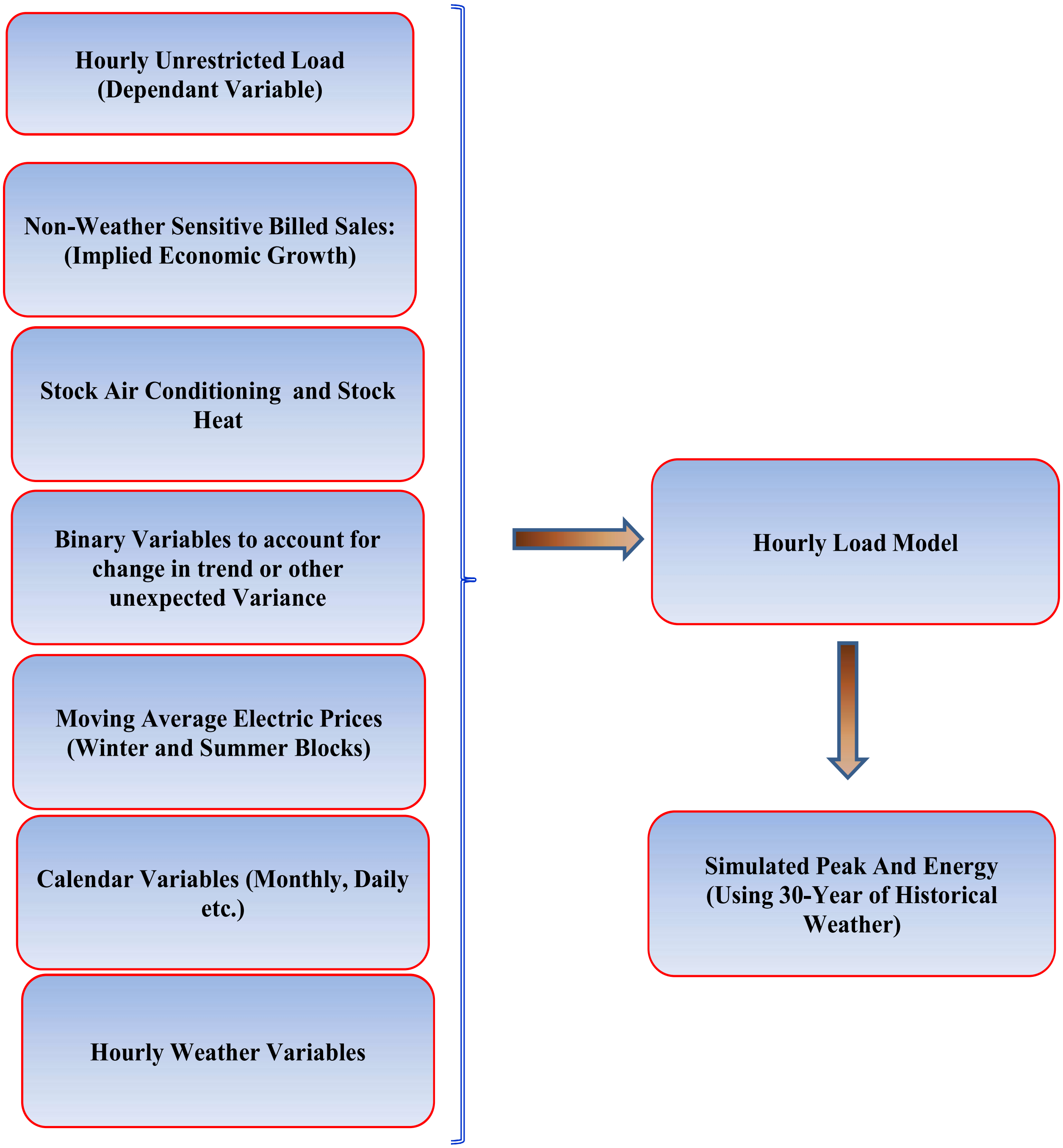
Once estimated, the set of hourly equations enable the forecasting of the aggregate hourly generation level loads for the DOM Zone conditional on any given realization of the weather-related explanatory variables, holding all other exogenous variables at projected levels. Due to the non-linear nature of the regression equations, a simulation-based approach is employed whereby hourly zonal loads conditioned on the actual hourly historical weather for each of the past 30 years is generated from the model to produce 30 individual "weather-year" trajectories each with its own projected hourly demands and period peaks and energy. By averaging period related quantities over the 30 weather-years the following quantities are forecasted over a 15 year horizon:

- Monthly Zonal Peak and Energy Demands
- Seasonal and Annual Zonal Peak Demands
- Expected Hourly Zonal Loads
- Yearly Typical 8760 Hourly Zonal Load Shape

It should be noted that the final forecasted peak and energy values include adjustments for projected incremental block loads from data centers, electric vehicles, or other significant load additions not reflected in the hourly regression equations.

A schematic of the process steps in developing the Peak and Energy model forecast is shown in Figure 6.1.1.1.

Figure 6.1.1.1 – Electric Peak and Energy Modeling Process



In conjunction with the final DOM Zone peak and energy forecast described above, a corresponding peak and energy forecast for the DOM LSE is developed by separately regressing the most recent ten years of historical LSE peaks and LSE energy on the historical DOM Zone peaks and energy, respectively, by month. The resulting estimated pair of peak and energy regression coefficients for each calendar month is applied to the corresponding forecasted monthly DOM Zone peaks and energy to calculate the forecasted DOM LSE peaks and energy. The forecasted DOM LSE load and firm contractual obligations form the final total load obligation of the DOM LSE.

6.1.2 Representative Hour Model Specification

<u>**Coefficient Name**</u>		<u>**Explanatory Variables**</u>
Intercept	*	1
MWHBASE	*	For the given hour, the non-weather sensitive residential sales regression effects (MWHRBASE) from the residential Energy Sales Model after scaling by number of billing days/24
[Indicator Variables (1 if True, 0 if False)]		
January - December (exc. Oct)	*	Month of Year
Monday…Saturday (exc. Sun)	*	Day of Week
REC1 - REC5	*	Recession
IRENE1	*	Hurricane Irene
MLKDay	*	Martin Luther King Day
PresDay	*	President's Day
GoodFriday	*	Good Friday
MemDay	*	Memorial Day
July4th	*	July 4th
LaborDay	*	Labor Day
ThanksG	*	Thanksgiving Day
FriAThanksG	*	Friday after Thanksgiving Day
NewYearEve	*	New Year's Eve Day
NewYearDay	*	New Year's Day
XMassLight	*	Holiday Lighting (day after Thanksgiving to day before Christmas)
XMasWkB4	*	Days leading up to Christmas day from prior Monday
XMasWk	*	Week of Christmas (days leading up to
XMasEve	*	Christmas Eve Day
XMasDay	*	Christmas Day
Ric_MD	*	If a daylight hour at Richmond
[Heating Variables:]		
HDDSpline	*	Value of equation (9) in Section 4.1.1.2
HDDWknd	*	Value of equation (13) in Section 4.1.1.2
LAGHDD	*	Value of equation (10) in Section 4.1.1.2

HotWind	*	Value of equation (14) in Section 4.1.1.1
HotClouds	*	Value of equation (15) in Section 4.1.1.1
ColdWind	*	Value of equation (11) in Section 4.1.1.2
ColdClouds	*	Value of equation (12) in Section 4.1.1.2

[Cooling Variables:]

LAGCDD	*	Value of equation (10) in Section 4.1.1.1
CDDWknd	*	Value of equation (16) in Section 4.1.1.1
CDDSplineFall	*	Value of equation (13) in Section 4.1.1.1
CDDSplineSpring	*	Value of equation (12) in Section 4.1.1.1
CDDSplineSummer	*	Value of equation (11) in Section 4.1.1.1
HEATColdClouds	*	ColdClouds * STOCKHT
HEATColdWind	*	ColdWind * STOCKHT
HEATHDDWknd	*	HDDWknd * STOCKHT
HEATHDDspline	*	HDDSpline * STOCKHT
HEATLagHDD	*	LAGHDD * STOCKHT
HEATPR2HDDspline	*	(HDDSpline * STOCKHT) * LAGPRW
AIRCDDSplineFall	*	CDDSplineFall * STOCKAC
AIRCDDSplineSpring	*	CDDSplineSpring * STOCKAC
AIRCDDSplineSummer	*	CDDSplineSummer * STOCKAC
AIRCDDWknd	*	CDDWknd * STOCKAC
AIRHOTClouds	*	HotClouds * STOCKAC
AIRHOTWind	*	HotWIND * STOCKAC
AIRLagCDD	*	LagCDD * STOCKAC
AIRPR1CDDSplineFall	*	(CDDSplineFall * STOCKAC) * PRESSUM
AIRPR1CDDSplineSpring	*	(CDDSplineSpring * STOCKAC) * PRESSUM
AIRPR1CDDSplineSummer	*	(CDDSplineSummer * STOCKAC) * PRESSUM
AIRPR1CDDWknd	*	(CDDWknd * STOCKAC) * PRESSUM
AIRPR1HOTClouds	*	(HOTClouds * STOCKAC) * PRESSUM
AIRPR1HOTWind	*	(HOTWind * STOCKAC) * PRESSUM
AIRPR1LagCDD	*	(LagCDD * STOCKAC) * PRESSUM
AIRPR2CDDSplineFall	*	(CDDSplineFall * STOCKAC) * LAGPRS
AIRPR2CDDSplineSpring	*	(CDDSplineSpring * STOCKAC) * LAGPRS
AIRPR2CDDSplineSummer	*	(CDDSplineSummer * STOCKAC) * LAGPRS
AIRPR2CDDWknd	*	(CDDWknd * STOCKAC) * LAGPRS
AIRPR2HOTClouds	*	(HOTClouds * STOCKAC) * LAGPRS
AIRPR2HOTWind	*	(HOTWind * STOCKAC) * LAGPRS
AIRPR2LagCDD	*	(LagCDD * STOCKAC) * LAGPRS

Where:

STOCKHT, STOCKAC: as defined in Appliance Stock Variable Development, Section 3.1
PRESSUM, AND LAGPRS: as defined in the Residential Sales Model specification, Section 4.1.

7.1 Unbilled Sales Model

7.1.1 Overview

In order to reconcile forecasted retail billed sales from the Sales Model with forecasted calendar month LSE energy demand from the Peak and Energy Model a model of unbilled sales is required since billed sales do not coincide with consumption in the calendar month. This reconciliation relies on the fact that daily zonal generation level load can be decomposed into daily system losses and daily energy sales. Energy sales can be further decomposed by billing cycle based on knowledge of the distribution of sales by billing cycle based on actual meter reading schedules. These schedules can then be used to assign the daily sales in each billing cycle to a particular billing month. Most sales are billed in the month in which those sales were generated or in the next month. On a few occasions, generation in the current month is recorded as sales in the previous billing month; and some sales are billed two months from the current month.

For the sake of simplicity, assume that daily generation is always 21,000 kWh, 21 billing cycles are in use, and customers in billing cycle 1 have their meters read on the first of the month. Now, consider a particular day, say February 2. On this day, the energy consumed by customers in cycle 1 is billed in the billing month of March (February billing month consumption spans January 2 – February 1). Consumption by customers in all the remaining cycles is billed in the billing month of February.

If one assumes equal distribution of sales by billing cycles and if all customers were assigned one of the 21 cycles, then 1,000 kWh of the assumed 21,000 kWh would be assigned to the billing month of March, and 20,000 kWh would be credited to the billing month of February.

Repeating this exercise for every day of the month in month t, each day's generation can be assigned into one of the categories below:

Name	Generated	When Billed
BC(t)	Current month	Current month
BN(t)	Current month	Next month
BF(t)	Current month	Two months later
BL(t)	Current month	Previous month

It follows then that generation level system demand can be spread over the same time frame as that of billed sales. Letting "billed load" represent the generation level equivalent of billed sales gives:

(1) Billed Load * BC(t) + BN(t-1) + BF(t-2) + BL(t+1)

The difference between billed load and billed sales is, of course, system losses. Hence, the following relationship holds between billed sales and billed load:

(2) Billed Sales * Billed Load - Billed Losses

The generation level equivalent of unbilled sales for month t is then:

(3) Unbilled Load * BN(t) + BF(t) + BF(t-1)

(4) Unbilled Sales * Unbilled Load - Unbilled Losses

If unbilled losses were known, equation (4) could be used to calculate unbilled sales. It is not possible to observe losses directly, but equation (2) provides a solution. Since billed sales are known and billed load can be calculated as described above, billed losses can be specified as a function of billed load. Regression analysis is used to estimate the relationship between losses and billed load.

For example, assume that the following relationship holds for daily losses as a function of daily output:

(5) Daily Losses * A + B * (Daily Output)

Then billed losses can be expressed as:

(6) Billed Losses * A * (Billing Days) + B * (Billed Load)

Billing Days is the average number of days in the billing cycle. Substituting equation (6) into equation (2) yields:

(7) Billed Sales * Billed Load - A * (Billed Days) - B * (Billed Load)

All elements are known except "a" and "b". Using historical data on billed sales and billed load, these parameters may be estimate using regression analysis.

Following the logic of equation (6), unbilled losses can be expressed as:

(8) Unbilled Losses * A * (Unbilled Days) + B * (Unbilled Load),

Unbilled Days is the average number of days of unbilled consumption across the billing cycles. Substituting equation (8) into equation (4) yields:

(9) Unbilled Sales * Unbilled Load - A * (Unbilled Days) - B * (Unbilled Load).

Using the estimates of "a" and "b" obtained from the regression analysis, equation (9) can be used to calculate unbilled sales since all other elements on the right hand side of that equation are now known.

In a forecasting mode, equation 7 above translates projected daily output into an estimate of total billed sales. To insure consistency between load estimates from the Peak and Energy Model, billed sales, and peak demand, the estimate of billed sales from equation 7 is compared with the estimate of total billed sales derived from the Sales Model. If there is a discrepancy, the forecasts from the Sales Model are adjusted to conform to the estimate from equation 7 above. As a practical matter the two estimates are usually within one percentage point of each other so that the adjustment is not large.

Virginia Electric and Power Company
Case No. PUR-2017-00051
Environmental Respondents
First Set

The following response to Question No. 40 of the First Set of Interrogatories and Requests for Production of Documents Propounded by the Environmental Respondents received on June 8, 2017 has been prepared under my supervision.

A K Vaswani
Ashwani Vaswani
Manager, Energy Market Quantitative
Analysis and Integrated Resource Planning
Dominion Energy Services, Inc.

The following response to Question No. 40(a) of the First Set of Interrogatories and Requests for Production of Documents propounded by the Environmental Respondents received on June 8, 2017 has been prepared under my supervision as it pertains to legal matters.

Vishwa B. Link
Vishwa B. Link
McGuireWoods LLP

Question No. 40

Reference p. 124 which suggests a "stochastic model" was created for each key source of portfolio risk, including "load (electricity demand)".

a) Provide all details of the stochastic model of load.
b) Provide the details of the "200 stochastic realizations" for load.
c) Describe how other outcomes (such as natural gas prices or basis) were connected to the load realizations within the Monte-Carlo analysis.

Response:

a) The Company objects to this request as overly broad, unduly burdensome and not relevant or reasonably calculated to lead to the production of admissible evidence in this Integrated Resource Plan proceeding to the extent it seeks "all details" without limitation.

Notwithstanding and subject to the foregoing objections, the Company provides the following response.

See Attachment ER Set 1-40 (AV) (1), which provides a more detailed description of the stochastic model of load, excluding specific probability distributions, which are algorithms within the proprietary software provided by PACE Global under license to the Company.

b) See Attachment ER Set 1-40 (AV) (2), which provides the "200 stochastic realizations" for load inputs to the AURORA model. The column labeled 'Iteration' identifies which of the 200 iterations the risk factor realization corresponds to.

c) See Attachment ER Set 1-40 (AV) (1), which provides a more detailed description of how natural gas basis was connected to the load realizations within the Monte-Carlo analysis. However, the specific probability distributions used exist as algorithms within the proprietary software provided by PACE Global under license to the Company.

Comprehensive Risk Analysis Technical Summary

Overview

Using the Pace Global methodology, the Alternative Plans, each treated as a fixed portfolio of existing and expansion resources plus demand-side measures, were evaluated and compared on the dimensions of average total production cost relative to two measures of cost-related risk, which are standard deviation cost and semi-standard deviation cost.

The Pace Global methodology is an adaptation of Modern Portfolio Theory, which attempts to quantify the trade-off that usually exists between portfolio cost and portfolio risk that is not addressed in the traditional least-cost planning paradigm. Measuring the risk associated with proposed expansion plans quantifies, for example, whether adopting any one particular plan comes with greater cost and risk for customers when compared to the cost and risk for competing plans. In the same way, comparing plans with different capacity mixes, and consequently with different cost and risk profiles, potentially reveals the value of generation mix diversity. It is important to note that it is impractical to include all possible sources of risk in this assessment but only the most significant drivers to plan cost and variability.

Due to the significant proportion of new solar capacity in each of the Alternative Plans, variability in aggregate solar generation is now considered by the Company as an additional key portfolio risk factor. This risk principally reflects actual seasonal weather driven solar PV generation variance that has been historically observed from solar PV facilities currently interconnected to the Company's network.

At a high level, the Pace Global methodology is comprised of the following steps:

- Identify and create a stochastic model for each key source of portfolio risk which in this analysis are:
    - Natural gas prices;
    - Natural gas basis;
    - Coal prices;
    - Load (electricity demand);
    - Hourly solar generation;
    - CO_2 emission allowance prices/ERC prices; and
    - New generation capital cost.
- Generate a set of stochastic realizations for the key risk factors within the PJM region and over the Study Period using Monte-Carlo techniques. For purposes of this analysis, 200 stochastic realizations were produced for each of the key risk factors;
- Subject each of the Alternative Plans separately to this same set of stochastic risk factor outcomes by performing 200 AURORA multi-area model production cost simulations, which cover a significant part of the Eastern Interconnection, using the risk factor outcomes as inputs;
- The AURORA simulation results were then used to calculate the expected levelized all-in average cost and the associated risk measures for each of the Alternative Plans.

The following Alternative Plans were evaluated under the comprehensive risk analysis:

- Plan A: No CPP
- Plan C^T: Intensity-Based Dual Rate
- Plan E^T: Mass-Based Existing Units
- Plan G^T: Mass-Based All Units
- Plan H^{NT}: New Nuclear

Given that Plans B^{NT}, D^{NT}, and F^{NT} are similar in design to their trading counterparts, the Company expects that the portfolio risk associated with these Plans will be similar.

In the sections which follow, each step of the Pace Global risk analysis methodology is described.

Risk Factors

Central to the Pace Global methodology is the identification and modeling of the key sources of resource plan cost risk. Once identified, each risk factor is parameterized with stochastic models which incorporate historical data and expert judgment in the development of forward projections reflecting their inherent variability. The stochastic model development incorporates any inter-relationships or correlations that hold between certain risk factors. Because of these correlations, it is important to view each stochastic "draw" as a joint realization of all the risk factors across all time points in the forecast period. A sample size of 200 draws, or joint realizations, was chosen as a reasonable compromise between the total time required to perform the AURORA simulation runs for each of the Alternative Plans and to achieve a statistically sufficient number of stochastic iterations, given that the modeled footprint extends to almost the entire Eastern Interconnection for over a 25-year forecast horizon.

Many of the risk factor stochastic projections include the combination of parametric distributions, developed from historical data, and additional uncertainty bands, developed through fundamental forecasts, that capture the potential for large deviations within the planning horizon. Such deviations, referred to by Pace Global as "quantum events", are relatively low probability events which result in large excursions both above and below expected values. It is important to capture such quantum events, because while the probability of such an event is relatively low over a short period of time, these events may occur more than once a long-term planning horizon. Over the past decade alone, several such events occurred, including the shale gas technology "breakthrough" that changed the market for natural gas; the recession of 2008 and its impacts on fuel prices and electric demand growth; and Hurricane Katrina, which had a significant impact on oil and natural gas markets in the Gulf of Mexico. Future "quantum" event uncertainties should be considered in areas such as technology costs (breakthroughs in renewables or storage), carbon emission regulations, future regime shifts in natural gas pricing, and the penetration of demand side management and behind-the-meter resources.

The magnitude and likelihood of quantum events are typically based on high and low scenarios for a commodity or quantity underlying a given risk factor. Computationally the process combines these scenario-based distributions with those driven solely by historical relationships and measures of volatility to develop a full range of stochastic outcomes. The stochastic generation process first draws a large initial sample of outcomes, which is stratified according to the assigned state probabilities. Subsequently, a set of 200 draws is drawn uniformly from the larger sample to create the final set used as inputs to the AURORA model.

The following key risk drivers were identified and modeled:

Fuel Prices

Fuel price volatility has been and no doubt will continue to be a major source of variability in production costs over both the short and long term. The impact of fuel price volatility is particularly important in the generation expansion context since in adopting a particular expansion plan the long-lived nature of generating assets effectively "locks-in" a corresponding dependency on a fixed portfolio of fuels. The chosen portfolio of fuels is then subject to market forces and technological changes that are usually well beyond the control of the utility.

The CPP commodity price forecast formed the baseline trajectory for the stochastic draws for the Henry Hub natural gas price, natural gas price basis to selected market hubs, and coal basin prices. The West Texas Intermediate (WTI) oil price functioned as the chief driver of coal transportation costs. With the exception of natural gas basis, the ICF-provided high and low Henry Hub price scenarios were used, as discussed below, as the high and low price regimes for the modeling of quantum events. For coal basin prices and WTI oil prices, the Company derived the high and low price ratio from 2016 ICF CPP Base price curves and applied to the 2017 ICF price curves, respectively. All price-related inputs to the AURORA simulations were in modeled in 2014 constant dollars. The stochastic draws for No CO_2 commodity prices were generated using the same methodology as the stochastic draws for CPP commodity prices.

Each fuel treated stochastically in the Pace Global methodology is discussed below in turn.

Natural Gas Prices

The monthly delivered price of natural gas was modeled as the sum of two components: the standard benchmark price at Henry Hub and a basis to each of the key market hubs within the PJM ISO region. ICF's expected, low, and high price forecasts provide the long-term mean to which prices revert. It should be noted that the Henry Hub prices initially generated were provisional in that, as will be discussed in treatment of carbon prices, they were subsequently revised through a commodity price feedback process to arrive at their final values for the AURORA model simulations once the CO_2 emission price draws were available.

The Pace Global methodology assigned a 15% probability to trajectories generated around the ICF high and low price scenarios, respectively, and a 70% probability to trajectories around the expected case. A one factor, log-normal, mean reverting monthly stochastic model was specified by Pace Global using historical Henry Hub spot prices and volatilities to generate a distribution of natural gas prices around the ICF forecasts. The estimated mean-reversion rate governed the speed to which prices revert within each price regime. All generated final price paths for Henry Hub were subject to a floor value of $1.95/mmbtu.

A one-factor, mean reverting daily model for the spread between Henry Hub and the delivered price of gas to each hub was used to model stochastic movements in gas basis. The stochastic terms in the basis model for each market hub were jointly related through a correlation matrix. Furthermore, an increase in gas basis volatility, as is typically observed in the winter, was induced by correlating higher basis outcomes with larger aggregate PJM electric demand outcomes in the winter months. The gas basis stochastic model explicitly incorporated varying levels of volatility at different points throughout PJM and at different times of the year, as well as expected changes in volatility over time in response to supply development, demand growth, and pipeline infrastructure expansion.

The basis to each of the following market hubs were modeled stochastically in this manner:

- Dominion South Point
- Transco Zone 5
- Transco Zone 6 Non-NY
- Leidy
- Lebanon
- TETCO M-3
- TCO – Appalachian Pool
- Chicago City Gate

The delivered price at Transco Zone 5 was assumed to apply to all gas-fired generating units within the DOM Zone. The delivered gas price (Henry Hub price + basis to hub) was subject to a floor value of $0.80/mmbtu.

Coal Prices

Though natural gas is rapidly becoming the fuel of choice for new fossil generation additions in PJM, existing coal resources currently make up approximately 40% of the fuel mix compared to 30% for natural gas. Coal price volatility will thus remain a significant source of production cost risk over most of the planning horizon. In the Pace Global approach, mine-mouth coal is differentiated into four principal basins: Northern and Central Appalachian, Illinois, and Powder River. Monthly price draws for the expected, high, and low price forecast cases were cross-correlated through an estimated cross-correlation matrix. A one-factor, log-normal, mean reverting stochastic price model was estimated for each basin around each of the ICF low, expected and high forecasts. The stochastic methodology assigned a 15% probability to trajectories generated around the ICF high and low price scenarios for each coal basin, respectively, and a 70% probability to trajectories around the ICF expected case.

The projected cost of transporting mine-mouth coal to plants within each modeled PJM zone was based on a fixed component for transportation costs from basin to delivered region and an uncertainty component based on a regression model of the relationship between historical transportation costs and the WTI benchmark price of oil. Stochastic outcomes for the WTI price were developed with a one-factor, mean reverting model. The regression function was then used to dynamically calculate the transportation cost component of the delivered coal price to each modeled PJM zone. Many coal plants within PJM effectively burn a blend of coals from two or more coal basins. In these cases an appropriately weighted average of the relevant stochastic basin price outcomes was used.

Load

The expected zonal load forecasts, except that for the DOM Zone, were taken from PJM's 2017 zonal-level unadjusted load forecast. The load forecast for the DOM Zone as well as that for the DOM LSE were the Company's own internal forecasts.

The load as a stochastic risk factor was modeled as a composite of three sub-factors: (1) short-term, monthly level weather variation, (2) long-term economic growth-related variability, and (3) variability in demand-side and energy efficiency effects as well as possible load increases due to technology-driven electric intensity. Each sub-factor is addressed in the Pace Global methodology as follows:

- Weather related volatility and variability in long-term economic growth was captured through multiple regression models of the relationship between historical monthly zonal peak and average energy demand and zonal historical heating and cooling degree days (HDD/CDD), humidity, and an index of annual personal income;
- Weather-related variability was simulated by randomly selecting the historical weather (heating and cooling degree days and humidity levels) from each of the past 19 years. This translated into short term deviations from the expected monthly peak and energy demand for each modeled PJM zone; and
- Variability in the long-term trend in zonal peak and energy demand as a result of economic growth uncertainty was generated as realizations of a geometric Brownian motion process for the index of personal income calibrated to historical mean growth (the drift parameter) and growth rate volatility. Stochastic realizations of personal income were then fed through the regression equations to create the corresponding load growth related perturbations.

Except for the DOM Zone and LSE, load volatility stemming from potential future trajectories of the penetration levels of energy efficiency/load management measures or load-building factors, such as plug-in hybrid electric vehicles or other electro-technologies was also modeled in the PJM zones. To accomplish this, Pace Global developed a tabled set of potential percentage load deviations for these factors based on research published by NERC and FERC. Two levels of demand-side reduction trajectories (expressed in annual percentage deviation terms) were assigned a probability of 5% and 20%, respectively, while the load building trajectory was modeled at a 25% probability. These probabilities drove the "quantum events" that were then combined with the "Business As Usual" trajectories which were based on the weather and economic growth outcomes.

In order to treat Dominion Energy Virginia-sponsored DSM as a fixed component of each plan, its penetration levels were not varied stochastically, but rather were treated as fixed, hourly-shaped demand reductions to the DOM Zone and LSE load forecasts. To accomplish this, however, the "quantum event" probabilistic trajectories described above were not modeled for the DOM Zone.

A Note on the Treatment of the DOM LSE Load

In the AURORA model simulations, resources are committed and dispatched hourly to meet zonal load and economically determined levels of inter-zonal interchange. Since integrated resource plans include only resources fully or partially owned by or under contract to the Company, it is important to note how production costs pertaining to each Alternative Plan, which include purchase and sales interchange transactions, are accounted for separately from non-Company owned or contracted resources in the modeled DOM Zone. This was accomplished by using a feature of the AURORA model that enables the user to identify a subset of zonal resources as a portfolio of resources to which a separate obligation load forecast is assigned. In this arrangement, the load assigned each of the Alternative Plans as portfolios were the forecasted LSE requirements load, which is approximately 85-88% of the DOM Zone load. The simulated hourly cost and quantity of DOM Zone purchase and sales interchange with inter-connected zones is allocated to the portfolio by AURORA with respect to the hourly requirements load.

Hourly Solar Generations

Hourly solar generation stochastic methodology only applied to solar generating units located in PJM & North and South Carolina. Based on the location, each solar generating unit was assigned an hourly generation solar profile such that in any given hour:

Expected Output MW = Nameplate MW x Solar Profile Factor

By analyzing the empirical distribution of the Company's historical actual generation each hour of the year, capacity multipliers were generated randomly and independently from the hourly distributions, assuming no correlation between adjacent hours and among locations. For each solar profile, 200 sets of hourly capacity multiplier draws were generated.

For each solar profile at each hour, the multipliers were also generated subject to the restriction such that if a solar unit's final output MW (expected output MW x capacity multiplier) exceeds its nameplate, the capacity multiplier would be reduced to the level at which output equals the nameplate. The average value of the multipliers in any given hour would typically still be close to one, though not exactly one.

Due to lack of hourly actual data outside the Company's service territory, the Company's hourly empirical generation distributions were applied to the rest of PJM as well as North and South Carolina.

Clean Power Plan Risk Modeling Assumptions

Each of the CPP-Compliant Plans was developed as the lowest cost means to comply with one of three corresponding CPP compliance options for the state of Virginia. In order to appropriately reflect the key features of the CPP in the risk simulations, the following general assumptions were implemented:

- With the exception of Virginia, the CPP compliance standards for each state within the simulation footprint, which included states within PJM and a significant portion of the U.S. Eastern Interconnection, were modeled according to the individual state compliance assumptions provided by ICF;
- The CPP compliance standard assumed for Virginia was consistent with the Alternative Plan being evaluated. In other words, for the Mass-Based plans, the Virginia generation units in question were evaluated using appropriate CO_2 allowance prices. Likewise for the Intensity-

Based plans, the Virginia generation units in question were evaluated using the appropriate ERC prices.

- Plan A: No CPP was evaluated using a set of stochastic realizations that assumed no CO_2 regulations whatsoever. All other plans evaluated in the comprehensive risk analysis were evaluated using stochastic realizations that assume a future CPP;
- Stochastic draws for carbon allowance prices were based on the annual expected prices in ICF's CPP commodity forecast and were applied to affected EGUs in any state, including Virginia under Plans E^T, G^T, and H^{NT}, that are assumed to adopt a Mass-Based compliance limit; and
- Risk scores included in the Portfolio Evaluation Scorecard for Scenario 1 (no CO_2 trading) Plans will correspond to the Scenario 2 (CO_2 trading) Plans evaluated in the process above.

Since in principle, higher carbon price levels induce greater demand for natural gas, the Pace Global methodology adjusts the initial realizations of Henry Hub prices based on the carbon price draws to account for this dynamic. Based on a fundamental analysis by Pace Global of the relationship between the change in coal-gas price spread as a function of the change in carbon price and consequently its effect on gas demand, the following feedback adjustment process was performed:

- For every stochastic draw, the dispatch cost of for a typical gas and coal plant is calculated from the Henry Hub, Central Appalachian coal, and CO_2 price outcomes;
- If the spread between gas and coal dispatch cost changes significantly enough to imply a change in gas demand, gas price is adjusted by a functional relationship to bring the coal-gas spread into parity. This adjustment may be either positive or negative, depending on the direction of the spread change. For example, a high CO_2 price is likely to drive coal generation down and natural gas generation upward, raising demand for natural gas thus pushing prices higher; and
- ERC Price draws are 100% correlated with the CO_2 price draws.

Capital Costs

Assumptions for expected engineering, procurement, and construction capital costs, fixed O&M, and non-fuel variable costs for each new generation type – advanced combined cycle, simple-cycle combustion turbine, on-shore wind and utility solar facilities – were supplied by ICF. These costs were applied to expansion options in the non-Dominion PJM zones. Corresponding costs for Company expansion units, including those for Unit 3 at the North Anna site and off-shore wind facilities, were based on internal Company estimates. With the exception of the Greensville combined cycle, which is present in all Alternative Plans, stochastic treatment of capital fixed charges were applied to expansion units going into commercial operation in 2019 or later.

Probability distributions for overnight capital costs by generation type were developed in the following manner:

- A log-normal distribution modeled the variability in the overnight capital cost (in 2014 dollars) in each year of commercial operation based on historical volatility in the key cost components of new builds, including labor, materials, and equipment. This variability was applied to estimates of capital costs provided by ICF for generic PJM expansion units and internal Company estimates for Company-owned expansion units.

An additional "quantum" distribution reflecting technology improvement uncertainty and cost variability not assignable to key labor or materials inputs was also introduced. The associated high and low ranges for capital costs, at the 90th and 5th percentiles, respectively, were set by the Company as percentages above and below their projected values by generation type as follows:

	Low	High
Simple-Cycle & Combined Cycle Gas	-2%	+8%
Solar & On-Shore Wind	-2%	+8%
Nuclear & Off-Shore Wind	-2%	+20%

Overnight capital cost stochastic draws were then translated into annual levelized fixed costs through application of an appropriate capital fixed charge rate.

For each of the Alternative Plans, outcomes for the annual levelized fixed costs for new capital additions vary by year of commercial operation for each expansion unit. In the non-Dominion PJM zones, both the timing and type of expansion unit is dynamically determined within each draw by the economic conditions implied by the stochastically realized levels of load, commodity prices, and capital fixed charges.

Virginia Electric and Power Company
Case No. PUR-2017-00051
Environmental Respondents
Third Set

The following response to Question No. 7 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the Environmental Respondents received on July 14, 2017 has been prepared under my supervision.

Dale E. Hinson
Manager, Gas Supply
Dominion Energy Fuel Services, Inc.

Question No. 7

Please provide for each natural gas fired power plant the name of the pipeline(s) and/or local distribution company (LDC) providing gas service for the purpose of electric generation.

a) Please also provide the name used by each such pipeline for the point of delivery to each such plant and where the plant is served by an LDC, the name used by the pipeline(s) serving the LDC where gas is received by the LDC for re-delivery to the plant.

Response

See Attachment ER Set 3-7 (DEH) for the requested information pertaining to Dominion Energy Virginia natural gas-fired power stations.

Attachment ER Set 3-7 (DEH)

Power Station	Pipeline / LDC	Upstream Pipeline Delivery Point	Delivery Point
Possum Point	Cove Point Pipeline	N/A	Possum Point
Yorktown	Virginia Natural Gas	DTI Quantico/VNG	Yorktown
TCO - Chesterfield	Columbia Gas of Virginia	TCO Meter #831082	Chesterfield
Gravel Neck	Columbia Gas of Virginia	TCO Meter #831081	Gravel Neck
Bellemeade	City of Richmond	TCO Meter #837059	Bellemeade
Gordonsville	Columbia Gas of Virginia	TCO Meter #833866	Gordonsville
Eliz River	Columbia Gas of Virginia	TCO Meter #833469	Elizabeth River
Darbytown	Virginia Natural Gas	DTI Quantico/VNG	Mechanicsville
DTI-Chesterfield	Virginia Natural Gas	DTI Quantico/VNG	Mechanicsville
Ladysmith	Virginia Natural Gas	DTI Quantico/VNG	Ladysmith
Remington	Columbia Gas of Virginia	Transco Remington/CGV	Remington
Altavista	Columbia Gas of Virginia	Transco Lynchburg/CGV	Altavista
Hopewell	Columbia Gas of Virginia	TCO Market Area 1-33/CGV	Hopewell
Rosemary	Piedmont Natural Gas	Transco Panda Energy Meter #7319	Rosemary
Bear Garden	Columbia Gas of Virginia	Transco Bear Garden/CGV	Bear Garden
Bremo	Columbia Gas of Virginia	Transco Bear Garden/CGV	Bremo
Warren County	Columbia Gas Transmission	N/A	Warren County #842564
Brunswick County	Transcontinental Gas Pipe Line Company, LLC	N/A	Brunswick County #9008686

Virginia Electric and Power Company
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Environmental Respondents
Third Set

The following response to Question No. 9 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the Environmental Respondents received on July 14, 2017 has been prepared under my supervision.

Dale E. Hinson
Manager, Gas Supply
Dominion Energy Fuel Services, Inc.

The following response to Question No. 9 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the Environmental Respondents received on July 14, 2017 has been prepared under my supervision as it pertains to legal matters.

Vishwa B. Link
McGuireWoods LLP

Question No. 9

Please identify the pipeline(s) that will serve the Greensville County Plant.

Response

The Company objects to this request to the extent that it seeks information that is publicly available to Environmental Respondents, Staff and any other party to this proceeding on the Commission's website in Case No. PUE-2015-00075. Notwithstanding and subject to the foregoing objections, the Company provides the following response.

The Company's Greensville County Power Station will receive firm capacity from the Transcontinental Gas Pipe Line, and will have access to the Atlantic Coast Pipeline.

Virginia Electric and Power Company
Case No. PUR-2017-00051
Environmental Respondents
Fourth Set

The following response to Question No. 10 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Environmental Respondents received on July 19, 2017 has been prepared under my supervision.

Jennifer Valaika for
Ashwani Vaswani
Manager, Energy Market Quantitative Analysis and Integrated Resource Planning
Dominion Energy Services, Inc.

Question No. 10

With respect to Response entitled "Attachment ER Set 1-1(a)" page 4, paragraph beginning "The basis to each of the following market hubs were modeled stochastically in this manner:", please provide the "basis" to each Hub from the Henry Hub at the temporal granularity level used in the model. By temporal granularity we mean please provide either projected daily, monthly or annual basis assumptions as used in the model for the planning period.

Response:

See Attachment ER Set 4-10 (AV) for the projected monthly gas prices and basis assumptions used in the model for the Planning Period. The column labeled *Iteration* identifies which of the 200 iterations the risk factor realization corresponds to.

Virginia Electric and Power Company
Case No. PUR-2017-00051
Environmental Respondents
Fourth Set

The following response to Question No. 12 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Environmental Respondents received on July 19, 2017 has been prepared under my supervision.

Jennifer Valaitis for
Ashwani Vaswani
Manager, Energy Market Quantitative Analysis and Integrated Resource Planning
Dominion Energy Services, Inc.

Question No. 12

With respect to Response entitled "Attachment ER Set 1-1(a)" page 1, bulleted paragraph beginning "Subject each of the Alternative Plans separately...", please answer the following questions to the best of your knowledge:

a) Of the "200 AURORA multi-area model production cost simulations" (each an iteration) modeled, which of those iterations were used by DOM in the IRP?
b) Was/were the "iteration"(s) used those resulting in: a) the highest costs, b) the lowest costs, c) the median costs?
c) Please provide a narrative answer as to why the choice chosen was chosen

Response:

a) All 200 iterations were used by the Company in the comprehensive risk analysis.
b) See the following table, which is responsive to this request (Table 4-12).

Table 4-12.

Plan	Highest Expected Levelized Average Cost Iteration Number	Lowest Expected Levelized Average Cost Iteration Number	Medium Expected Levelized Average Cost Iteration Number
Plan A: No CPP	126	9	123
Plan C^T: Intensity-Based Dual Rate	159	38	71
Plan E^T: Mass-Based Existing Units	159	38	173
Plan G^T: Mass-Based All Units	159	154	186
Plan H^{NT}: New Nuclear Plan	159	38	70

c) The 200 iterations were chosen at random within the proprietary software provided by Siemens PACE Global under license to the Company.

Virginia Electric and Power Company
Case No. PUR-2017-00051
Environmental Respondents
Fourth Set

The following response to Question No. 13 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Environmental Respondents received on July 19, 2017 has been prepared under my supervision.

Jennifer Valaika for
Ashwani Vaswani
Manager, Energy Market Quantitative Analysis and
Integrated Resource Planning
Dominion Energy Services, Inc.

Question No. 13

With respect to Response entitled "Attachment ER Set 1-1(a)" page 4, paragraph beginning "The Delivered Price at Transco Zone 5...", please explain; "Why the Delivered Price at Transco Zone 5 was "assumed to apply to all gas fired generating units within the DOM Zone"?

Response:

It is a simplifying assumption that the Company made in order to make the comprehensive risk analysis feasible. To generate the 200 iterations price paths, the methodology requires historical prices at a liquid hub in order to calculate volatilities. Transco Zone 5 is the only available liquid pricing Hub that is representative of gas prices in Virginia.

Virginia Electric and Power Company
Case No. PUR-2017-00051
Environmental Respondents
Sixth Set

The following response to Question No. 18 of the Sixth Set of Interrogatories and Requests for Production of Documents Propounded by the Environmental Respondents received on July 25, 2017 has been prepared under my supervision.

Bruce Petrie

Bruce Petrie
Manager - Generation System Planning
Dominion Energy Virginia

Question No. 18

Reference the response to ER Set 3-4 (a)-e, where Dominion states that the data request "seeks specific firm transportation agreement information, including pricing and terms that are currently committed to and not currently in-service . . . which were not inputs to the 2017 Plan analysis." With respect to the costs of subscribing to service on the proposed Atlantic Coast Pipeline (ACP), for the period(s) of the IRP that cover the post in-service date of the proposed ACP agreement(s), please explain how those costs are reflected in any or all of Dominion's:

a) "1_Fuel Backup" calculations;
b) "1_Fuel Analysis" calculations; or
c) Integrated Resource Plan.

Response:

The Company used the PLEXOS model to develop the various capacity expansion plans in the 2017 Plan.

a) The expected gas firm transportation service costs for the ACP pipeline were included in row 9 (Virginia jurisdictional cost) of the sheet "1_Fuel Backup" starting in the 2018/19 fuel year.

b) See the response to subpart (a) of this request.

c) For planning purposes, firm transportation costs for committed natural gas pipelines (such as ACP) were considered sunk, while firm transportation costs for new gas-fired power plants were treated as incremental. Sunk costs were not an input into the PLEXOS model since the costs would be applied to all potential expansion plans equally. Only incremental firm transportation costs for new gas-fired resources were an input into PLEXOS model. See the Company's response to Question No. 58 of ER Set 1.

CERTIFICATE OF SERVICE

I hereby certify that the following have been served with a true and accurate copy of the foregoing via first-class mail, postage pre-paid:

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DATED: August 11, 2017